BROWN TOM INC /DE
Form 10-K/A
August 05, 2003

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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K/A

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

For the Fiscal Year Ended December 31, 2002

or

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

For the Transition Period from to
Commission File Number 001-31308

Tom Brown, Inc.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**95-1949781** (I.R.S. Employer Identification No.)
555 Seventeenth Street **Suite 1850** **Denver, Colorado** (Address of principal executive offices)	**80202** (Zip Code)

303-260-5000
(Registrant's telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act: **None**

Securities Registered Pursuant to Section 12(g) of the Act:
Common Stock, $.10 par Value
Convertible Preferred Stock, $.10 par Value
(Title of Class)

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 ý No o

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

Indicate by check mark whether the Registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2). Yes ý No o

The aggregate market value of the Registrant's Common Stock held by non-affiliates was approximately $944,162,050 as of June 28, 2002 (based on the last reported sale price of such stock on the New York Stock Exchange Composite Tape on that day).

As of March 11, 2003, there were 39,398,903 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive proxy statement for the 2003 Annual Meeting of Stockholders to be held on May 8, 2003 are incorporated by reference into Part III.

TOM BROWN, INC.

FORM 10-K

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EXPLANATORY NOTE

Tom Brown, Inc. (the "Company") is filing this amendment in response to comments received from the Securities and Exchange Commission regarding the Company's Annual Report on Form 10-K/A for the fiscal year ended December 31, 2002 that was originally filed on March 25, 2003. This report significantly revises the disclosures pertaining to the Company's business, the Company's properties, the Company's legal proceedings, management's discussion and analysis of financial condition and results of operations, and the Company's financial statements. This report continues to speak as of the date of the original filing, and the Company has not updated the disclosure in this report to speak as of a later date. All information contained in this report and the original filing is subject to updating and supplementing as provided in the Company's periodic reports filed with the Securities and Exchange Commission.

PART I

ITEM 1. *Business*

GENERAL

Tom Brown, Inc. (the "Company") was organized in 1955 as a privately-owned drilling company known as Scarber-Brown Drilling Company and in 1959 as Tom Brown Drilling Company, Inc. In 1968, the Company merged into Gold Metals Consolidated Mining Company, a publicly-traded Nevada corporation. The name of the Company after the merger was changed to Tom Brown Drilling Company, Inc. and to Tom Brown, Inc. in 1971. In February 1987, the Company changed its state of incorporation from Nevada to Delaware. In 1999, the Company relocated its headquarters and executive offices to 555 Seventeenth Street, Suite 1850, Denver, Colorado 80202 and its telephone number at that address is (303) 260-5000. Unless the context otherwise requires, all references to the "Company" include Tom Brown, Inc. and its subsidiaries.

The Company is engaged primarily in the exploration for, and the acquisition, development, production, marketing and sale of, natural gas, natural gas liquids and crude oil in North America. The Company's activities are conducted principally in the Wind River and Green River Basins of Wyoming, the Piceance Basin of Colorado, the Paradox Basin of Utah and Colorado, the Val Verde Basin and Permian Basin of west Texas and southeastern New Mexico, the east Texas Basin and the western Canadian Sedimentary Basin. The Company also, to a lesser extent, conducts exploration and development activities in other areas of the continental United States and Canada.

In December 2000, the Company initiated a cash tender for all the outstanding stock of Stellarton Energy Corporation ("Stellarton"). This transaction was completed on January 12, 2001.

The Company's industry segments are (i) the exploration for, and the acquisition, development and production of, natural gas, natural gas liquids and crude oil, (ii) the marketing, gathering, processing and sale of natural gas and (iii) the drilling of gas and oil wells.

Except for its gas and oil leases with governmental entities and other third parties who enter into gas and oil leases or assignments with the Company in the regular course of its business and options to purchase gas and oil leases with the Eastern Shoshone and Northern Arapaho Tribes, the Company has no material patents, licenses, franchises or concessions that it considers significant to its gas and oil operations.

The nature of the Company's business is such that it does not maintain or require a substantial amount of products, customer orders or inventory. The Company's gas and oil operations are not subject to renegotiations of profits or termination of contracts at the election of the federal government.

The Company has not been a party to any bankruptcy, receivership, reorganization or similar proceeding, except in connection with its participation as a joint proponent of a plan of reorganization for Presidio Oil Company in 1996.

BUSINESS STRATEGY

The Company's business strategy is to increase stockholder value through the discovery, acquisition and development of long-lived gas and oil reserves in areas where the Company has industry knowledge and operations expertise. The Company's principal investments have been in natural gas prone basins, which the Company believes will continue to provide the opportunity to accumulate significant long-lived gas and oil

reserves at attractive prices. The expansion into Canada in 2001 was an extension of this fundamental strategy.

The Company's year-end domestic acreage position was approximately 2,677,000 gross (1,773,000 net) acres (including options) located primarily in the Wind River and Green River Basins of Wyoming, the Piceance Basin of Colorado, the Paradox Basin of Colorado and Utah, and the Permian, Val Verde and east Texas Basins of Texas where the Company can utilize its geological and technical expertise and its control of operations for the further development and expansion of these areas. Approximately 89% of the net acreage is undeveloped.

The Company's year-end Canadian acreage position located in western Alberta was approximately 540,000 gross (359,000 net) acres. Approximately 78% of the net acreage is undeveloped.

Additionally, by staying focused in its core basins, the Company continues to develop more effective drilling and completion techniques which can improve overall economic efficiency.

The Company increased its reserves in 2002 over 2001 by 2% due primarily to continued drilling success in its core areas. Year-end proved reserves were 750 billion cubic feet equivalent ("Bcfe"), compared to year-end 2001 reserves of 732 Bcfe. At December 31, 2002, the Canadian reserve base was 82 Bcfe compared to 77 Bcfe at December 31, 2001. Since December 31, 1995, the Company has increased proved reserves at a compounded annual growth rate of 22%, or from 188 Bcfe to 750 Bcfe.

Reserve replacement for 2002 was 137% from all sources and 119% from extensions, discoveries and revisions only. The Company's reserve to production ratio was 8.8 years at year-end 2002 compared to 9.6 years at year-end 2001. In addition to increasing reserves, the Company also increased its production 12% from 76.4 Bcfe in 2001 to 85.5 Bcfe in 2002.

The Company markets a majority of its operated gas production and some third party gas in the Rocky Mountains through Retex, Inc. ("Retex"), the Company's wholly-owned marketing subsidiary.

The Company also conducts gas gathering and processing activities in the Rocky Mountain area. Initially, these functions were conducted through Wildhorse Energy Partners, LLC ("Wildhorse") which was owned 55% by Kinder Morgan, Inc. ("KM") and 45% by the Company. In November 2000, the Wildhorse gathering and processing assets were distributed to the Company in anticipation of the dissolution of Wildhorse. KM received the Wildhorse storage facility and a cash payment of $14.7 million. TBI Field Services, Inc. ("TBIFS") was formed as a wholly-owned subsidiary of Tom Brown, Inc. to administer these gathering and processing assets. In 2001, TBIFS selectively sold many of the gathering and processing facilities received in the Wildhorse asset distribution, retaining only those gathering systems considered integral to the Company's gas and oil reserve base. As the Company directly owns and operates several gas processing and gathering systems adjacent to its areas of operations, the systems ultimately retained by TBIFS after the Wildhorse dissolution were merged into the Company's operations in 2002 and TBIFS ceased to function as a separate entity.

The Company plans to continue to selectively pursue acquisitions of gas and oil properties in its core areas of activity and, in connection therewith, the Company from time to time will be involved in evaluations of, or discussions with, potential acquisition candidates. The consideration for any such acquisition might involve the payment of cash and/or the issuance of equity or debt securities.

Notwithstanding the Company's historical ability to implement the above strategy, the Company may not be able to successfully implement its strategy in the future. See "Risk Factors."

AREAS OF ACTIVITY

The following discussion focuses on areas the Company considers to be its core areas of operations and those that offer the Company the greatest opportunities for further exploration and development activities.

Wind River, Green River, Paradox, and Piceance Basins

The Wind River and Green River Basins of Wyoming, the Piceance Basin of Colorado, and the Paradox Basin of Colorado and Utah account for the major portion of the Company's current and anticipated domestic exploration and development activities with approximately 74% of the Company's proved reserves at December 31, 2002. The Company owns interests in 1,278 producing wells in these basins that averaged net daily production of 159 Mmcfe for 2002. The Company has approximately 1,565,000 gross (1,224,000 net) developed and undeveloped acres in these basins, including option acreage of approximately 281,000 gross undeveloped (253,000 net) acres in the Wind River Basin.

In 2002, the Company drilled and completed 16 wells in the Wind River basin, the majority of which were located in the Pavillion field where the Company holds a 92% working interest. In the Piceance basin, the Company drilled 26 wells in 2002 (completing 25). The Piceance wells were principally drilled at the Company's 100% owned White River Dome coal bed methane project in western Colorado.

The Rocky Mountain region has experienced limited natural gas transportation capacity. Recognizing these restrictions, various pipelines have constructed lines and are continuing to add additional pipeline capacity into this area.

Permian and Val Verde Basins

The Permian and Val Verde Basins accounted for approximately 9% of the Company's proved reserves at December 31, 2002. The Company's share of production from these basins averaged 28 Mmcfepd for 2002. The Company holds between 30% to 50% working interests in approximately 46,800 gross (20,300 net) acres in the Val Verde Basin. The Permian Basin contains significant oil reserves for the Company, located primarily in the Sprayberry Field.

In the Deep Valley exploration project area of the Permian Basin, the Company drilled a horizontal Montoya well in 2001 which tested non-commercial in the Montoya formation but will be tested in the Devonian formation in 2003. In 2002, the Company successfully completed a Devonian well in this area with a 50% working interest that commenced production in June 2002 at initial rates approximating 10 Mmcfepd declining to 2.5 Mmcfepd in early 2003. Two wells were drilled subsequent to this discovery in 2002 that are currently being evaluated. The Company also attempted a horizontal re-entry in Deep Valley to test the Devonian section of a well in 2002 that was unsuccessful.

East Texas Basin

The Company participates in a continuing developmental drilling program in the Mimms Creek Field (Bossier Sands play) in Freestone County, Texas. During 2002, 11 wells were drilled and completed under this program, with the Company owning working interests ranging from 50% to 62.5%.

In recent years, the Company has acquired approximately 80,000 net acres in the James Lime (horizontal) Trend of the east Texas Basin. In 2001, the Company drilled seven wells in the James Lime (horizontal) Trend of which five were initially completed. This large regional play is in its early stages of development and the Company is working to determine its potential based upon the initial production rates and variable decline rates of the wells drilled to date.

Canada

The western Canadian Sedimentary Basin accounted for approximately 11% of the Company's proved reserves at December 31, 2002. The Company's share of production from these basins averaged 24 Mmcfepd in 2002. The Company owns interests in 252 wells and has approximately 540,000 gross (359,000 net) developed and undeveloped acres in this area. In 2002, the Company drilled 13 wells in Canada of which 12 were completed. These wells were primarily located in the Carrot Creek and Edson fields operated by the Company.

BUSINESS DEVELOPMENTS

Current Developments in the Gas and Oil Business

Acquisition of Stellarton Energy Corporation

Effective January 16, 2001, the Company purchased 100% of Stellarton Energy Corporation ("Stellarton") for $95 million. The acquisition was funded through a five-year Canadian term loan. Stellarton's assets are located in western Alberta, Canada with estimated total net proved reserves (after royalty) of 58.8 billion cubic feet (Bcf) of gas and 2.82 million barrels of oil and natural gas liquids for total equivalent proved reserves of 75.5 Bcfe, as of the date of this acquisition. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Capital Resources and Liquidity Debt" for a description of the material terms of the Company's bank credit facility, including the Canadian term loan.

Acquisition of Rocky Mountain Assets

In June 2002, the Company purchased Rocky Mountain gas and oil properties located within the Greater Green River Basin of Wyoming for approximately $8.1 million from an unrelated third party. In December 2002, the Company acquired additional assets within this basin from this seller for $6.8 million. The acquisition cost of both of these transactions was net of normal closing adjustments. The acquired interests from these two transactions included an estimated 12.7 Bcfe of proved reserves.

In June 2000, the Company purchased an additional working interest in the Company-operated Pavillion Field in the Wind River Basin in Wyoming. The Company acquired the additional interest from State Farm Mutual Automobile Insurance Company, a stockholder of the Company. The acquired interests included an estimated 24 Bcfe of proved reserves purchased for total consideration of $15.2 million net of normal closing adjustments.

Acquisition of the Assets of Unocal Corporation

In July 1999, the Company completed an acquisition of substantially all of the Rocky Mountain oil and gas assets of Unocal Corporation ("Unocal") for 5.8 million shares of common stock and $5 million in cash for a total purchase price of $68.5 million ($60.9 million after deducting normal purchase price adjustments).

The Unocal oil and gas assets are primarily located in the Paradox Basin of southwestern Colorado and southeastern Utah. These assets and properties compliment the Company's 163,000 net undeveloped acres in the Paradox Basin.

Included in the acquisition was the Lisbon Plant, a modern sophisticated cryogenic (60 million cubic feet per day capacity) natural gas processing plant that extracts natural gas liquids and merchantable helium; and separates carbon dioxide, hydrogen sulfide and nitrogen from the raw gas stream. The net proved reserves of these Unocal properties were estimated to be 93.2 billion cubic feet equivalent of gas as of the closing date of July 1, 1999. Approximately 65,000 net undeveloped acres were also acquired.

Current Developments in the Marketing, Gathering and Processing Business

In September 1999, KM became the operator of, and 55% partner in, Wildhorse as a result of a merger with KN Energy, Inc. ("KNE"). Wildhorse was formed in connection with the Company's 1996 acquisition of KN Production Company, the wholly-owned oil and gas production subsidiary of KNE. Wildhorse was created to provide services related to natural gas, natural gas liquids and other natural gas products, including gathering, processing and storage services and field services. The Company owned 45% of Wildhorse since its inception. Effective September 1, 1999, Wildhorse assigned 100% of its marketing operations to Retex, the Company's wholly-owned marketing subsidiary. Additionally, firm transportation contracts were assigned 55% to KM and 45% remained in Retex. In November 2000, the Wildhorse gathering and processing assets were distributed to the Company in anticipation of the dissolution of Wildhorse. KM received the Wildhorse storage facility and a cash payment of $14.7 million. "TBIFS" was formed as a wholly-owned subsidiary of Tom Brown, Inc. to administer the gathering and processing assets received in this distribution.

In 2001, TBIFS selectively sold many of the gathering and processing facilities received in the Wildhorse asset distribution. The systems sold were considered non-strategic to the Company's operations and, as these divestitures were part of the Wildhorse integration process, the net cash proceeds of $24.0 million were recorded as a reduction to the investment in gathering assets. After these divestitures, the only significant asset retained was the Wind River gathering system in one of the Company's core areas. In 2002, the Company liquidated TBIFS to transfer the remaining gathering and processing assets to Tom Brown, Inc.

Current Developments in the Drilling Business

Acquisition of Assets of W. E. Sauer Companies, LLC

On January 7, 1998, the Company completed the acquisition of all of the drilling assets of W. E. Sauer Companies L.L.C. of Casper, Wyoming for approximately $8.1 million. The Company operates the assets in its subsidiary, Sauer Drilling Company ("Sauer"), and plans to continue to serve the drilling needs of operators in the central Rocky Mountain region in addition to drilling for the Company. The assets included five drilling rigs, tubular goods, a yard and related assets. Subsequent to the acquisition, Sauer has acquired three additional drilling rigs for approximately $4 million.

MARKETS

The Company's gas production has historically been sold primarily under month-to-month contracts with marketing companies and local distribution companies (LDC's). During 2001 and 2002, there was a significant amount of volatility in the prices received for natural gas. Monthly closing gas prices in 2001 as measured on the New York Mercantile Exchange ("NYMEX") varied from a high of $9.98 per million British thermal unit ("Mmbtu") for January 2001 to a low of $1.83 per Mmbtu for October 2001. In 2002, the NYMEX gas prices varied from a high of $4.14 per Mmbtu in December 2002 to a low of $2.01 per Mmbtu in February 2002. The U.S. Rocky Mountain region represented approximately 68% of the Company's 2002 gas production and 66% of its 2001 production. The price of gas in the Rocky Mountains at the Colorado Interstate Gas (CIG) hub was $1.25 and $.77 per Mmbtu below the NYMEX posted gas price on average for 2002 and 2001, respectively. The Company's Canadian production base has also been subject to price volatility. In 2001, gas production from the Canadian fields was subject to gas pricing that ranged from $1.10 per Mmbtu above the February 2001 NYMEX price to a price that was $.98 per Mmbtu below the October 2001 NYMEX price. In 2002, the Canadian gas prices continued to be volatile ranging from $.12 per Mmbtu below the NYMEX posting for February 2002 to $1.24 below the August 2002 NYMEX price.

The Company markets most of its oil production with independent third-party resellers and refiners at market ("posted") prices. These posted prices generally reflect the prices determined by the trading of West Texas Intermediate ("WTI") oil futures contracts on the NYMEX, with adjustments due to basis differential and for the quality of oil produced.

NYMEX prices for both gas and oil are influenced by weather, seasonal demand, levels of storage, production levels and a variety of political and economic factors over which the Company has no control. See "Risk Factors."

Production Volumes, Unit Prices and Costs

The following table sets forth certain information regarding the Company's volumes of production sold and average prices received associated with its production and sales of natural gas, natural gas liquids and crude oil for each of the years ended December 31, 2002, 2001 and 2000.

	Years Ended December 31,		
United States	**2002**	**2001**	**2000**
Production Volumes:			
Natural Gas (MMcf)	65,781	57,163	51,199
Crude Oil (MBbls)	623	723	773
Natural Gas Liquids (MBbls)	1,189	1,074	1,074
Net Average Daily Production Volumes:			
Natural Gas (Mcf)	180,221	156,611	139,888
Crude Oil (Bbls)	1,708	1,979	2,113
Natural Gas Liquids (Bbls)	3,258	2,943	2,934
Average Sales Prices:			
Natural Gas (per Mcf):			
Price received	$ 2.10	$ 3.43	$ 3.46
Effect of hedges	$	$ 0.30	$
Net sales price	$ 2.10	$ 3.73	$ 3.46
Crude Oil (per Bbl)	$ 23.20	$ 22.64	$ 28.05
Natural Gas Liquids (per Bbl)	$ 11.39	$ 13.25	$ 16.77
Average Production Cost (per Mcfe)(1)	$ .57	$ .70	$ .76

	Years Ended December 31,	
Canada	**2002**	**2001**
Production Volumes:		
Natural Gas (MMcf)	6,386	6,661
Crude Oil (Mbbls)	220	158
Natural Gas Liquids (Mbbls)	193	143
Net Average Daily Production Volumes:		
Natural Gas (Mcf)	17,496	18,247
Crude Oil (Bbls)	601	432
Natural Gas Liquids (Bbls)	529	392
Average Sales Prices:		
Natural Gas (per Mcf):		
Price received	$ 3.07	$ 3.49
Effect of hedges	$ (0.03)	$
Net sales price	$ 3.04	$ 3.49
Crude Oil (per Bbl)	$ 23.86	$ 25.11
Natural Gas Liquids (per Bbl)	$ 16.17	$ 20.23
Average Production Cost (per Mcfe)(1)	$ .55	$ .62

(1) Includes production costs and taxes on production. (Mcfe means one thousand cubic feet of natural gas equivalent, calculated on the basis of six barrels of oil and natural gas liquids to one Mcf of gas.)

Customers

Gas and oil sales to ConocoPhillips, Inc. accounted for 17% of the Company's gas and oil sales for the year ended December 31, 2002. No other purchaser accounted for 10% or more of the Company's total gas and oil revenue during 2002. Because there are numerous other parties available to purchase the Company's production, the Company believes the loss of ConocoPhillips would not materially affect its ability to sell natural gas or crude oil.

In 2002, a previous purchaser of the Company's natural gas liquids in the Paradox Basin of Colorado and Utah defaulted on payments owed the Company totaling $6.2 million. In the fourth quarter of 2002, the Company received a $1.4 million cash settlement in connection with this default. For additional information, please see Note 10 Related Parties and Significant Customers in the Notes to the Company's Consolidated Financial Statements.

Competition

The Company encounters strong competition from major oil companies and independent operators in acquiring properties and leases for the exploration for, and the development and production of, natural gas and crude oil. Competition is particularly intense with respect to the acquisition of desirable undeveloped gas and oil leases. The principal competitive factors in the acquisition of undeveloped gas and oil leases include the availability and quality of staff and data necessary to identify, investigate and purchase such leases, and the financial resources necessary to acquire and develop such leases. Many of the Company's competitors have financial resources, staffs and facilities substantially greater than those of the Company. In addition, the producing, processing and marketing of natural gas and crude oil is affected by a number of factors which are beyond the control of the Company, the effect of which cannot be accurately predicted. See "Risk Factors."

The principal raw materials and resources necessary for the exploration and development of natural gas and crude oil are leasehold prospects under which gas and oil reserves may be discovered, drilling rigs and related equipment to drill for and produce such reserves and knowledgeable personnel

to conduct all phases of gas and oil operations. The Company must compete for such raw materials and resources with both major oil companies and independent operators.

Retex encounters competition from other natural gas transportation and marketing entities in the marketing of gas. Such competition may materially affect the volumes and margins that Retex may derive.

Employees

At December 31, 2002, the Company had 429 employees of which 103 were employed by Sauer. None of the Company's employees are represented by labor unions or covered by any collective bargaining agreement. The Company considers its relations with its employees to be satisfactory.

REGULATION UNITED STATES

Regulation of Gas and Oil Production

Gas and oil operations are subject to various types of regulation by state and federal agencies. Legislation affecting the gas and oil industry is under constant review for amendment or expansion. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the gas and oil industry and its individual members, some of which carry substantial penalties for failure to comply. The regulatory burden on the gas and oil industry increases the Company's cost of doing business and, consequently, affects its profitability.

States in which the Company conducts its gas and oil activities regulate the production and sale of natural gas and crude oil, including requirements for obtaining drilling permits, the method of developing new fields, the spacing and operation of wells and the prevention of waste of gas and oil resources. In addition, most states regulate the rate of production and may establish maximum daily production allowables for wells on a market demand or conservation basis.

Gas Price Controls

Prior to January 1993, certain natural gas sold by the Company was subject to regulation by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 ("NGPA"). The NGPA prescribed maximum lawful prices for natural gas sales effective December 1, 1978. Effective January 1, 1993, natural gas prices were completely deregulated and sales of the Company's natural gas are now made at market prices. The majority of the Company's gas sales contracts either contain decontrolled price provisions or already provide for market prices.

Oil Price Controls

Sales of crude oil, condensate and gas liquids by the Company are not regulated and are made at market prices.

Environmental Regulation

The Company's natural gas and oil exploration, development and production operations are subject to stringent federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental agencies, such as the U.S. Environmental Protection Agency (EPA), issue regulations to implement and enforce such laws, which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties or may result in injunctive relief for failure to comply. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically sensitive and other protected areas, require remedial action to prevent pollution from former operations, such as plugging abandoned wells or closing pits, and impose substantial liabilities for pollution resulting from the Company's operations. The regulatory burden on the natural gas and oil industry increases the cost of doing business and consequently affects profitability. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect the Company's operations and financial position, as well as the gas and oil industry in general. Management believes that the Company is in substantial compliance with current applicable environmental laws and regulations and the Company has not experienced any material adverse effect from compliance with these environmental requirements; this trend, however, may not continue in the future.

The Comprehensive Environmental Response, Compensation and Liability Act, as amended, also known as CERCLA or Superfund, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other pollutants into the environment. Rocno Corporation, a wholly owned subsidiary of the Company, has been identified as a potentially responsible party, or PRP, at the Sheridan Superfund Site in Waller County, Texas. However, given the large number of PRPs identified at this site, as well as Rocno's relatively small proportionate share of estimated cleanup costs for the site, management of the Company does not expect that Rocno's participation in the cleanup of the Sheridan Superfund Site will have a material adverse effect on the Company's operations. See "Item 3. Legal Proceedings."

The Resource Conservation and Recovery Act (RCRA), as amended, generally does not regulate most wastes generated by the exploration and production of natural gas and oil. RCRA specifically excludes from the definition of hazardous waste "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy." However, these wastes may be regulated by the EPA or state agencies as solid waste. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils, may be regulated as hazardous waste. Although the costs of managing solid and hazardous waste may be significant, the Company does not expect to experience more burdensome costs than similarly situated companies involved in natural gas and oil exploration and production.

The Company currently owns or leases, and has in the past owned or leased, numerous properties that for many years have been used for the exploration and production of gas and oil. Although the Company has utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by the Company or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under the Company's control. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under such laws, the Company could be required to remove or remediate previously disposed wastes or property contamination, or to perform remedial plugging or pit closure operations to prevent future contamination.

The Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other gas and oil wastes, into state waters or waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit

issued by the EPA or the state. These proscriptions also prohibit certain activity in wetlands unless authorized by a permit issued by the U.S. Army Corps of Engineers. The EPA has also adopted regulations requiring certain gas and oil exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans. The Company's management believes that the Company has obtained or applied for all permits required under the Clean Water Act. Sanctions for failure to comply with Clean Water Act requirements include administrative, civil and criminal penalties, as well as injunctive relief.

The Clean Air Act (CAA), as amended, restricts the emission of air pollutants from many sources, including natural gas and oil operations. New facilities may be required to obtain permits before work can begin, and existing facilities may be required to incur capital costs in order to remain in compliance. In addition, more stringent regulations governing emissions of toxic air pollutants are being developed by the EPA, and may increase the costs of compliance for some facilities. The Company's management believes that the Company is in substantial compliance with all air emissions regulations and that the Company has or has applied for all necessary permits for its operations. Management also believes that air emission permits for operation of the Company's Pavillion Gas Plant in Fremont County, Wyoming and Lisbon Gas Plant in Moab, Utah are material to the Company's operations. Currently, the Pavillion Gas Plant holds a Title V air emission operating permit that will not expire until January 9, 2009. The Lisbon Gas Plant is expected to be issued a Title V air emissions operating permit in the third quarter of 2003 and, until it receives the Title V permit, continues to operate under a state-issued Approval Order that allows the facility to conduct operations under the state permit until such time as the Title V permit is issued. The Title V permit, once issued, is expected to have an initial term of at least five years, and renewals and extensions of air emissions permits are routinely granted. The costs associated with obtaining and maintaining these permits are not material.

Indian Lands

The Company's Muddy Ridge and Pavillion Fields are located on the Wind River Indian Reservation. The Eastern Shoshone and Northern Arapaho Tribes levy taxes on the production of hydrocarbons. The Bureau of Indian Affairs, Minerals Management Service and Bureau of Land Management of the U.S. Department of the Interior perform certain regulatory functions relating to operation of Indian gas and oil leases. The Company owns interests in three leases in the Pavillion Field which were issued pursuant to the provisions of the Act of August 21, 1916, for initial terms of 20 years each, with a preferential right by the lessee to renew the leases for subsequent ten-year terms. The leases were renewed for an additional ten-year term in 1992, effective as of June 23, 1993. One of these leases has been amended to provide for incremental extensions of this lease term of up to an additional 12 years by drilling and completing additional wells on each lease prior to June 2003. In December of 2000 the Company added to its Tribal base inventory around the Pavillion Field by signing eleven additional ten-year leases covering nearly 25,800 net acres. The Company is currently awaiting final approval of the leases by the Bureau of Indian Affairs and has deferred drilling initially planned for early 2003 until the agreement between the Tribes and the Company on a methodology for payment of Tribal gas royalties is approved and executed by the Tribal Council and the Minerals Management Service.

REGULATION CANADA

Regulation of Gas and Oil Production and Price Controls

The oil and natural gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government. It is not expected that any of these controls or regulations will affect our operations in a manner materially different than they would affect other oil and gas companies of similar size.

In Canada, oil and gas exports are subject to regulation by the National Energy Board (NEB), an independent federal regulatory agency. The Company does not, at present, export oil or gas under the terms of these regulations, but may be affected if regulations imposed by the NEB act to restrict the sales of gas and oil by other companies. Exports are also subject to the North American Free Trade Agreement (NAFTA) which became effective on January 1, 1994. NAFTA carries forward most of the material energy terms contained in the Canada-U.S. Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the United States or Mexico will be allowed provided that any export restrictions do not: (i) reduce the proportion of energy resource exported relative to domestic use (based upon the proportion prevailing in the most recent 36-month period), (ii) impose an export price higher than the domestic price, and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements. NAFTA contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements, which is important for Canadian natural gas exports.

The provincial government of Alberta also regulates the volume of natural gas which may be removed from the province for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime on Crown lands is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by government regulation and are generally calculated as a percentage of the value of the gross

production, and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced.

From time to time the governments of Canada and Alberta have established incentive programs which have included royalty rate deductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced recovery projects. At present, few of these programs are currently in effect.

In Alberta, certain producers of oil or natural gas are currently entitled to a credit against the royalties to the Crown by virtue of the ARTC (Alberta royalty tax credit) program. The credit is determined by applying a specified rate to a maximum of $2 million CDN of Alberta Crown royalties payable for each producer or associated group of producers. The specified rate is a function of the Royalty Tax Credit reference price (RTCRP) which is set quarterly by the Alberta Department of Energy and ranges from 25% to 75%, depending on oil and gas par prices for the previous calendar quarter. The provincial government of Alberta has proposed changes to the ARTC program which have not been finalized.

Environmental Regulation

In Canada, the oil and natural gas industry is currently subject to environmental regulation pursuant to provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced or utilized in association with certain oil and gas industry operations. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. The Company operates within this regulatory framework and continues to monitor and evaluate the impact of the regulatory regime when determining parameters for engaging in gas and oil activities and investments in Canada. In addition, the Company routinely obtains permits for its facilities and operations in accordance with these applicable laws and regulations on an ongoing basis. There are no known issues that have a significant adverse effect on the permitting process or permit compliance status of any of the Company's facilities or operations.

In Alberta, environmental compliance has been governed by the Alberta Environmental Protection and Enhancement Act ("AEPEA") since September 1, 1993. In addition, AEPEA also imposes certain environmental responsibilities on oil and natural gas operators in Alberta and in certain instances also imposes penalties for violations. The Company has not received any violation notices under the AEPEA or from any Canadian environmental regulatory agency. The Company believes that it is in substantial compliance with current applicable Canadian environmental laws and regulations and that continued compliance with existing requirements would not have a material adverse impact on the Company's results of operations or financial condition.

FORWARD-LOOKING STATEMENTS

The information in this Form 10-K includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical or present facts, that address activities, events, outcomes and other matters that the Company plans, expects, intends, assumes, believes, budgets, predicts, forecasts, projects, estimates or anticipates (and other similar expressions) will, should or may occur in the future are forward-looking statements. These forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this Form 10-K.

Forward-looking statements may appear in a number of places and include statements with respect to, among other things:

- any expected results or benefits associated with the Company's acquisitions;
- estimates of the Company's future natural gas, crude oil and natural gas liquids production, including estimates of any increases in production;
- planned capital expenditures and the availability of capital resources to fund capital expenditures;
- estimates of the Company's gas and oil reserves;
- the impact of U.S. and Canadian political and regulatory developments;

- the Company's future financial condition or results of operations and future revenues and expenses; and
- the Company's business strategy and other plans and objectives for future operations.

Forward-looking statements are subject to all of the risks and uncertainties, many of which are beyond the Company's control, incident to the exploration for and acquisition, development, production, marketing and sale of natural gas, natural gas liquids and crude oil in North America. These risks include, but are not limited to, commodity price volatility, third party interruption of sales to market, inflation, lack of availability of goods and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating proved natural gas and oil reserves and in projecting future rates of production and timing of development expenditures and the other risks described in this Form 10-K.

Reserve engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data and the interpretation of that data by geological engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, these revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates are generally different from the quantities of natural gas and oil that are ultimately recovered.

Should one or more of the risks or uncertainties described above or elsewhere in this Form 10-K occur, or should underlying assumptions prove incorrect, the Company's actual results and plans could differ materially from those expressed in any forward-looking statements. The Company specifically disclaims all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaims any resulting liability for potentially related damages.

All forward-looking statements attributable to the Company are expressly qualified in their entirety by this cautionary statement.

RISK FACTORS

The Company's business is subject to a number of risks including, but not limited to, those described below:

Natural gas and oil price declines and volatility could adversely affect the Company's revenues, cash flows and profitability.

The Company's revenues, profitability and future rate of growth depend substantially upon the market prices of natural gas and oil, which fluctuate widely. Sustained declines in gas and oil prices may adversely affect the Company's financial condition, liquidity and results of operations. Factors that can cause market prices of natural gas and oil to fluctuate include:

- relatively minor changes in the supply of and demand for natural gas and oil;
- market uncertainty;
- the level of consumer product demands;
- weather conditions;
- U.S. and foreign governmental regulations;
- the price and availability of alternative fuels;
- political and economic conditions in oil producing countries, particularly those in the Middle East;
- the foreign supply of natural gas and oil;

the price of gas and oil imports; and

overall U.S. and foreign economic conditions.

The Company cannot predict future natural gas and oil prices. At various times, excess domestic and imported supplies have depressed gas and oil prices. Lower prices may reduce the amount of natural gas and oil that the Company can produce economically and may also require the Company to write down the carrying value of its gas and oil properties. Substantially all of the Company's natural gas and oil sales are made in the spot market or pursuant to contracts based on spot market prices, not long-term fixed price contracts.

In an attempt to reduce price risk, the Company periodically enters into hedging transactions with respect to a portion of its expected future production. Such transactions may not reduce the risk or minimize the effect of any decline in natural gas or oil prices. Any substantial or extended decline in the prices of or demand for natural gas or oil would have a material adverse effect on the Company's financial condition and results of operations.

If natural gas and oil prices decrease or exploration efforts are unsuccessful, the Company may be required to take writedowns.

There is a risk that the Company will be required to write down the carrying value of its gas and oil properties, which would reduce the Company's earnings and stockholders' equity. A writedown could occur when gas and oil prices are low or if the Company has substantial downward adjustments to its estimated proved reserves, increases in its estimates of development costs or deterioration in its exploration results.

The Company accounts for its natural gas and crude oil exploration and development activities utilizing the successful efforts method of accounting. Under this method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Gas and oil lease acquisition costs are also capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for gas and oil leases, are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities. The capitalized costs of the Company's gas and oil properties may not exceed the estimated future net cash flows from its properties. If capitalized costs exceed future net revenues, the Company must write down the costs of the properties to the Company's estimate of fair market value. Any such charge will not affect the Company's cash flow from operating activities, but it will reduce the Company's earnings and stockholders' equity.

The application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as developmental or exploratory, which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Wells may be completed that are assumed to be productive and actually deliver gas and oil in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. Wells are drilled that have targeted geologic structures that are both developmental and exploratory in nature and an allocation of costs is required to properly account for the results. The evaluation of gas and oil leasehold acquisition costs requires judgment to estimate the fair value of these costs with reference to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

The Company reviews its gas and oil properties for impairment whenever events and circumstances indicate a decline in the recoverability of their carrying value. Once incurred, a writedown of gas and oil properties is not reversible at a later date even if gas or oil prices increase. Given the complexities associated with gas and oil reserve estimates and the history of price volatility in the gas and oil markets, events may arise that would require the Company to record an impairment of the recorded book values associated with gas and oil properties. In 1998, the Company recognized a pre-tax impairment of $51.3 million, primarily as a result of the low market prices in effect at that time; similar impairments may be required in the future.

The marketability of the Company's production depends mostly upon the availability, proximity and capacity of gas gathering systems, pipelines and processing facilities.

The marketability of the Company's production depends upon the availability, operation and capacity of gas gathering systems, pipelines and processing facilities. The unavailability or lack of capacity of these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. United States federal, state and foreign regulation of gas and oil production and transportation, general economic conditions and changes in supply and demand could adversely affect the Company's ability to produce and market natural gas and oil. If market factors changed dramatically, the financial impact on the Company could be substantial. The availability of markets and the volatility of product prices are beyond the Company's control and represent a significant risk.

The Company may not receive payment for a portion of its future production.

The Company's revenues are derived principally from uncollateralized sales to customers in the gas and oil industry. The concentration of credit risk in a single industry affects the Company's overall exposure to credit risk because customers may be similarly affected by changes in

economic and other conditions. The publicly disclosed deteriorating financial conditions and recently reduced credit ratings of certain purchasers of production increase the possibility that the Company may not receive payment for a portion of its future production. In 2002, a previous purchaser of the Company's natural gas liquids in the Paradox Basin of Colorado and Utah defaulted on payments owed the Company totaling $6.2 million; to date, the Company has received only a $1.4 million cash settlement in connection with this default. The Company has attempted to obtain credit protections such as letters of credit, guarantees and prepayments from certain of its purchasers. The Company is unable to predict, however, what impact the financial difficulties of certain purchasers may have on its future results of operations and liquidity.

Estimates of gas and oil reserves are uncertain and inherently imprecise.

This Form 10-K contains estimates of the Company's proved gas and oil reserves and the estimated future net revenues from such reserves. Actual results will likely vary from amounts estimated and any significant variance could have a material adverse effect on the Company's future results of operations.

Gas and oil reserve estimates are based upon various assumptions, including assumptions required by the Securities and Exchange Commission relating to gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating gas and oil reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise.

Actual future production, gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable gas and oil reserves will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves set forth in this document and the information incorporated by reference. The Company's properties may also be susceptible to hydrocarbon drainage from production by other operators on adjacent properties. In addition, the Company may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing gas and oil prices and other factors, many of which are beyond its control.

At December 31, 2002, approximately 26% of the Company's U.S. estimated proved reserves were proved undeveloped, while 8% of the Company's Canadian estimated proved reserves were proved undeveloped. Proved undeveloped reserves and proved developed non-producing reserves, by their nature, are less certain than proved developed producing reserves. Estimation of these non-producing categories is nearly always based on volumetric calculations rather than the performance data used to estimate producing reserves. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Production revenues from proved non-producing reserves will not be realized until some time in the future. The reserve data assumes that the Company will make significant capital expenditures to develop its reserves. Although the Company has prepared estimates of its gas and oil reserves and the costs associated with these reserves in accordance with industry standards, these estimated costs may not be accurate, development may not occur as scheduled and actual results may not be as estimated.

You should not assume that the estimated present value of future net cash flow referred to in this Form 10-K is the current fair value of the Company's estimated gas and oil reserves. In accordance with Securities and Exchange Commission requirements, the estimated discounted future net cash flows from proved reserves are based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. Any changes in consumption by gas purchasers or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of gas and oil properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the Securities and Exchange Commission to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor for the Company.

The Company may not be able to obtain adequate financing to execute its operating strategy.

The Company has historically addressed its short and long-term liquidity needs through the use of cash flow provided by operating activities, the use of bank credit facilities and the issuance of equity securities. Without adequate financing, the Company may not be able to successfully execute its operating strategy. The Company continues to examine the following alternative sources of capital:

- bank borrowings or the issuance of debt securities;
- the issuance of common stock, preferred stock or other equity securities; and
- joint venture financing.

The availability of these sources of capital will depend upon a number of factors, some of which are beyond the Company's control. These factors include general economic and financial market conditions, natural gas and oil prices and the Company's market value and operating performance. The Company may be unable to execute its operating strategy if it cannot obtain adequate capital.

The Company may not be able to fund its planned capital expenditures.

The Company spends and will continue to spend a substantial amount of capital for the acquisition, exploration, exploitation, development and production of gas and oil reserves. If low natural gas and oil prices, operating difficulties or other factors, many of which are beyond the Company's control, cause its revenues and cash flows from operating activities to decrease, the Company may be limited in its ability to spend the capital necessary to complete its capital expenditures program. In addition, if the Company's borrowing base under its credit facility is re-determined to a lower amount, this could adversely affect the Company's ability to fund its planned capital expenditures. The Company's capital expenditures, including acquisitions, were $161.7 million during 2002, $358.1 million during 2001 and $150.5 million during 2000. The Company anticipates capital and exploration expenditures between $155 and $185 million in 2003, approximately 90% of which will be allocated to exploration and development activity. After utilizing its available sources of financing, the Company may be forced to raise additional equity or debt proceeds to fund such expenditures. Additional equity or debt financing or cash flow provided by operations may not be available to meet the Company's capital expenditures requirements.

The Company may not be able to replace production with new reserves.

The Company's reserves will decline as they are produced unless the Company acquires properties with proved reserves or conducts successful development and exploration drilling activities. The Company's future natural gas and oil production is highly dependent upon its level of success in finding or acquiring additional reserves, which it may not be successful in doing.

The successful acquisition of producing properties requires an assessment of a number of factors, many of which are beyond the Company's control. These factors include recoverable reserves, future gas and oil prices, operating costs and potential environmental and other liabilities, title issues and other factors. Such assessments are inexact and their accuracy is inherently uncertain. In connection with such assessments, the Company performs a review of the subject properties, which it believes is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, the review will not permit a buyer to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. The Company may not be able to acquire properties at acceptable prices because the competition for producing gas and oil properties is intense and many of the Company's competitors have financial and other resources that are substantially greater than those available to the Company.

The Company's operations are subject to numerous risks of gas and oil drilling and production activities.

Gas and oil drilling and production activities are subject to numerous risks, including the risk that no commercially productive natural gas or oil reservoirs will be found. Gas and oil drilling and production activities may be shortened, delayed or canceled as a result of a variety of factors, many of which are beyond the Company's control. These factors include:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- weather conditions;
- shortages in experienced labor; and
- shortages or delays in the delivery of equipment.

The prevailing prices of natural gas and oil also affect the cost of and the demand for drilling rigs, production equipment and related services.

New wells that the Company drills may not be productive and the Company may not recover all or any portion of its investment. The cost of drilling and completing wells is often uncertain. Drilling for natural gas and oil may be unprofitable. Drilling activities can result in dry wells

and wells that are productive but do not produce sufficient net revenues after operating and other costs to recoup drilling costs.

The Company's industry experiences numerous operating risks.

The exploration, development and operation of gas and oil properties involves a variety of operating risks including the risk of fire, explosions, blowouts, pipe failure, abnormally pressured formations and environmental hazards, including oil spills, gas leaks, pipeline ruptures or discharges of toxic gases. If any of these industry-operating risks occur, the Company could have substantial losses. Substantial losses may be caused by injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties, and suspension of operations.

The Company maintains insurance against some, but not all, of the risks described above. Such insurance may not be adequate to cover losses or liabilities. Also, the Company cannot predict the continued availability of insurance at premium levels that justify its purchase. The terrorist attacks on September 11, 2001 and the changes in the insurance markets attributable to those attacks may make some types of insurance more difficult to obtain. The Company may be unable to secure the level and types of insurance it would otherwise have secured prior to September 11th. The Company may not be able to maintain insurance in the future at rates it considers reasonable. The occurrence of a significant event, not fully insured or indemnified against, could materially and adversely affect the Company's financial condition and operations.

Terrorist attacks aimed at the Company's facilities could adversely affect its business.

On September 11, 2001, the United States was the target of terrorist attacks of unprecedented scale. Since the September 11th attacks, the U.S. government has issued warnings that U.S. energy assets may be the future targets of terrorist organizations. These developments have subjected the Company's operations to increased risks. Any future terrorist attack at the Company's facilities, or those of its purchasers, could have a material adverse effect on the Company's business.

The covenants in the agreements governing the Company's debt could negatively impact the Company's financial condition, results of operations and business prospects.

The terms of the agreements governing the Company's debt impose significant restrictions on the Company's ability and the ability of its subsidiaries to take a number of actions that the Company may otherwise desire to take, thereby negatively impacting the Company's financial condition, results of operations and business prospects. These provisions restrict:

- the incurrence of additional debt;
- the payment of dividends on stock, redemption of stock or redemption of subordinated debt;
- the making of investments;
- the creation of liens on the Company's assets;
- the sale of assets;
- the guaranteeing of other indebtedness;
- the entering into agreements that restrict dividends from the Company's subsidiaries to the Company;
- the merger, consolidation or transfer of all or substantially all of the Company's assets; and
- the entering into transactions with affiliates.

The Company's level of indebtedness, and the covenants contained in the agreements governing the Company's debt, could have important consequences on its operations, including, for example, making the Company vulnerable to increases in interest rates, because debt under the Company's credit facility will be at variable rates.

The Company may be required to repay all or a portion of its debt on an accelerated basis in certain circumstances. If the Company fails to comply with the covenants and other restrictions in the agreements governing its debt, it could lead to an event of default and the acceleration of the Company's repayment of outstanding debt. The Company's ability to comply with these covenants and other restrictions may be affected by events beyond the Company's control, including prevailing economic and financial conditions. The credit facility allows the lenders one scheduled redetermination of the borrowing base each December. In addition, the lenders may elect to require one unscheduled redetermination in the event the borrowing base utilization exceeds 50% of the borrowing base at any time for a period of 15 consecutive business days. Upon a redetermination, if borrowings in excess of the revised borrowing capacity were outstanding, the Company could be forced to repay a portion of its bank debt.

The Company may not have sufficient funds to make such repayments. If the Company is unable to repay its debt out of cash on hand, it could attempt to refinance such debt, sell assets or repay such debt with the proceeds from an equity offering. The Company may not be able to generate sufficient cash flow from operating activities to pay the interest on its debt. In addition, future borrowings, equity financings or proceeds from the sale of assets may not be available to pay or refinance such debt. The terms of the Company's debt, including its credit facility, may also prohibit the Company from taking such actions. Factors that will affect the Company's ability to raise cash through an offering of its capital stock, a refinancing of its debt or a sale of assets include financial market conditions and the Company's market value and operating performance at the time of such offering or other financing. The Company may not successfully complete any such offering, refinancing or sale of assets.

Competition within the Company's industry may adversely affect its operations.

Competition in the Wind River and Green River Basins of Wyoming, the Piceance Basin of Colorado and the Paradox Basin of Utah and Colorado is intense, particularly with respect to the acquisition of producing properties and proved undeveloped acreage. The Company competes with major gas and oil companies and other independent producers of varying sizes, all of which are engaged in the acquisition of properties and the exploration and development of such properties. Many of the Company's competitors have financial resources and exploration and development budgets that are substantially greater than the Company's, which may adversely affect the Company's ability to compete.

The Company may incur substantial costs to comply with the various U.S. federal, state and local environmental laws and regulations that affect its gas and oil operations.

The Company's gas and oil operations are subject to stringent U.S. federal, state and local laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the incurrence of investigatory or remedial obligations, or the imposition of injunctive relief.

The environmental laws and regulations to which the Company is subject may:

- require the acquisition of a permit before drilling commences;
- restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and
- impose substantial liabilities for pollution resulting from Company operations.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require the Company to make significant expenditures to maintain compliance, and may otherwise have a material adverse effect on the earnings, results of operations, competitive position or financial condition of the Company. Over the years, the Company has owned or leased numerous properties for gas and oil activities upon which petroleum hydrocarbons or other materials may have been released by the Company or by predecessor property owners or lessees who were not under the Company's control.

Under applicable environmental laws and regulations, including CERCLA, RCRA and analogous state laws, the Company could be held strictly liable for the removal or remediation of previously released materials or property contamination at such locations regardless of whether the Company was responsible for the release or if the Company's operations were standard in the industry at the time they were performed. For additional information about the specific environmental laws and regulations to which the Company is subject, see " Regulation United States Environmental Regulation."

The loss of key personnel could adversely affect the Company's ability to operate.

The Company's operations are dependent upon a relatively small group of key management and technical personnel. The unexpected loss of the services of one or more of these individuals could have an adverse effect on the Company. The Company considers all of its executive officers to be key employees. Such individuals may not remain with the Company for the immediate or foreseeable future. The Company does not maintain key man insurance on any employee, and has an employment contract only with James D. Lightner, the Company's Chairman, Chief Executive Officer and President.

Hedging transactions may limit the Company's potential gains.

In order to manage its exposure to price risks in the marketing of gas and oil, the Company periodically enters into gas and oil price hedging arrangements, such as commodity swap agreements, forward sale contracts, commodity futures, options and similar agreements, with respect to a portion of its expected production. While intended to reduce the effects of volatile gas and oil prices, such transactions, depending on the hedging instrument used, may limit the Company's potential gains if gas and oil prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose the Company to the risk of financial loss in certain circumstances, including instances in which:

- production is substantially less than expected;
- the counterparties to the Company's futures contracts fail to perform the contracts; or
- a sudden, unexpected event materially impacts gas or oil prices.

The Company does not pay dividends.

The Company has never declared or paid any cash dividends on its common stock and has no intention to do so in the near future. The restrictions on the Company's present or future ability to pay dividends are included in the provisions of the Delaware General Corporation Law. In addition, the Company has entered into a credit facility that contains provisions that may have the effect of limiting or prohibiting the payment of dividends.

The Company's Certificate of Incorporation and rights plan have provisions that discourage corporate takeovers and could prevent stockholders from realizing a premium on their investment.

Certain provisions of the Company's Certificate of Incorporation and stockholders' rights plan and the provisions of the Delaware General Corporation Law may encourage persons considering unsolicited tender offers or other unilateral takeover proposals to negotiate with the Company's board of directors rather than pursue non-negotiated takeover attempts. As a result, these provisions could have the effect of preventing stockholders from realizing a premium on their investment.

The Company's Certificate of Incorporation authorizes the Company's board of directors to issue preferred stock without stockholder approval and to set the rights, preferences and other designations, including voting rights of those shares, as the board may determine. Additional provisions include restrictions on business combinations and the availability of authorized but unissued common stock. These provisions, alone or in combination with each other and with the rights plan described below, may discourage transactions involving actual or potential changes of control, including transactions that otherwise could involve payment of a premium over prevailing market prices to stockholders for their common stock.

In 1991, the Company adopted a rights plan, pursuant to which uncertificated stock purchase rights were distributed to stockholders at a rate of one right for each share of common stock held of record as of March 15, 1991. On March 1, 2001, the Company amended and restated the rights plan. Each right entitles the registered holder to purchase, for a $120 per share exercise price, shares of common stock or other securities of the Company (or, under certain circumstances, of the acquiring person) worth twice the per share exercise price of the right. The rights plan is designed to enhance the Company's ability to prevent an acquirer from depriving stockholders of the long-term value of their investment and to protect stockholders against attempts to acquire the Company by means of unfair or abusive takeover tactics. However, the existence of the rights plan may impede a takeover not supported by the Company's board, including a takeover that may be desired by a

majority of stockholders or involving a premium over the prevailing stock price.

ITEM 2. ***Properties***

GAS AND OIL PROPERTIES

The principal properties of the Company consist of developed and undeveloped gas and oil leases. Generally, the terms of developed gas and oil leaseholds are continuing and such leases remain in force by virtue of, and so long as, production from lands under lease is maintained. Undeveloped gas and oil leaseholds are generally for a primary term, such as five or ten years, subject to maintenance with the payment of specified minimum delay rentals or extension by production. The Company also has options to lease undeveloped gas and oil leaseholds on Eastern Shoshone and Northern Arapaho Tribal lands. The oil and gas leases had initial terms of twenty years and the Company has a preferential right to negotiate with the Tribes for renewals of subsequent ten-year terms.

TITLE TO PROPERTIES

As is customary in the gas and oil industry, the Company makes only a cursory review of title to undeveloped gas and oil leases at the time they are acquired by the Company. However, before drilling commences, the Company causes a thorough title search to be conducted, and any material defects in title are remedied prior to the time actual drilling of a well on the lease begins. The Company believes that it has good title to its gas and oil properties, some of which are subject to immaterial encumbrances, easements and restrictions. The gas and oil properties owned by the Company are also typically subject to royalty and other similar non-cost bearing interests customary in the industry. The Company does not believe that any of these encumbrances or burdens materially affects the Company's ownership or use of its properties.

ACREAGE

The following table sets forth the gross and net acres of developed and undeveloped gas and oil leases held by the Company at December 31, 2002. Included in the table are approximately 281,000 gross (253,000 net) acres in Wyoming under gas and oil option agreements acquired from certain Indian tribes.

	DEVELOPED		**UNDEVELOPED**	
	GROSS	**NET**	**GROSS**	**NET**
Colorado	106,681	87,045	551,438	476,074
Louisiana	1,419	671	7	4
Michigan			303	121
Montana	102	76	158,307	26,443
Nebraska			31,455	30,861
New Mexico	15,412	3,952	2,440	2,092
North Dakota			2,960	80
Texas	112,526	42,852	353,906	229,960
Utah	6,599	5,821	111,573	104,396
West Virginia	3,852	1,240	150,041	74,820
Wyoming	116,632	57,983	950,962	628,396
Canada	143,520	80,889	396,664	278,503
Other			10	2
Total	506,743	280,529	2,710,066	1,851,752

"Gross" acres refer to the number of acres in which the Company owns a working interest. "Net" acres refer to the sum of the fractional working interests owned by the Company in gross acres.

GAS AND OIL RESERVES

Estimates of the Company's gas, oil and natural gas liquids reserves, including future net revenues and the present value of future net cash flows, were prepared by the Company's petroleum engineering staff and reviewed by Ryder Scott (independent petroleum consultants). Guidelines established by the Securities and Exchange Commission were utilized to prepare these reserve estimates. Estimates of gas, oil and natural gas liquids reserves and their estimated values require numerous engineering assumptions as to the productive capacity and production

rates of existing geological formations and require the use of certain Securities and Exchange Commission guidelines as to assumptions regarding costs to be incurred in developing and producing reserves and prices to be realized from the sale of future production.

Accordingly, estimates of reserves and their value are inherently imprecise and are subject to constant revision and change and should not be construed as representing the actual quantities of future production or cash flows to be realized from the Company's gas and oil properties or the fair market value of such properties. See "Risk Factors."

Certain additional unaudited information regarding the Company's reserves, including the present value of future net cash flows, is set forth in the Notes to Consolidated Financial Statements included herein.

The Company has no gas, oil and natural gas liquids reserves or production subject to long-term supply or similar agreements with foreign governments or authorities.

Estimates of the Company's total proved gas and oil reserves have not been filed with or included in reports to any federal authority or agency other than the Securities and Exchange Commission.

PRODUCTIVE WELLS

The following table sets forth the gross and net productive gas and oil wells in wells in which the Company owned an interest at December 31, 2002.

	Productive Wells			
	Gross		Net	
	Gas	Oil	Gas	Oil
Colorado	556	4	360.21	3.13
Louisiana	4		1.98	
New Mexico	22	30	5.51	9.63
Utah	9	21	8.24	20.91
Texas	191	258	81.67	100.02
West Virginia	89		32.95	
Wyoming	639	6	320.39	3.69
Canada	150	102	76.34	72.39
Total	1,660	421	887.29	209.77

A "gross" well is a well in which the Company owns a working interest. "Net" wells refer to the sum of the fractional working interests owned by the Company in gross wells.

GAS AND OIL DRILLING ACTIVITY

The following table sets forth the Company's gross and net interests in exploratory and development wells drilled during the periods indicated.

	United States			Canada		
	Year ended December 31,					
	2002			2002		
Type of Well	**Gross**	**Net**	**Net%**	**Gross**	**Net**	**Net%**
Exploratory						
Gas	5	3.0	47	1	1.0	100

	United States			Canada		
Oil						
Dry	7	3.4	53			
	12	6.4	100	1	1.0	100
Development						
Gas	66	43.7	95	8	5.6	62
Oil				3	2.5	27
Dry	3	2.4	5	1	1.0	11
	69	46.1	100	12	9.1	100
Total	81	52.5		13	10.1	

	United States			Canada		
	Year ended December 31,					
	2001			2001		
Type of Well	**Gross**	**Net**	**Net%**	**Gross**	**Net**	**Net%**
Exploratory						
Gas	7	6.6	49			
Oil						
Dry	12	6.7	51	4	3.6	100
	19	13.3	100	4	3.6	100
Development						
Gas	139	98.1	97	22	16.0	71
Oil				1	.5	2
Dry	7	3.3	3	8	6.1	27
	146	101.4	100	31	22.6	100
Total	165	114.7		35	26.1	

	United States		
	Year ended December 31,		
	2000		
Type of Well	**Gross**	**Net**	**Net%**
Exploratory			
Gas			

	United States		
Oil			
Dry	3	2.3	100
	3	2.3	100
Development			
Gas	63	33.7	93
Oil	1	.2	1
Dry	4	2.3	6
	68	36.2	100
Total	71	38.5	

At December 31, 2002, 5 gross (2.6 net) development wells and 6 gross (4.7 net) exploration wells were in various stages of drilling and completion in Texas, Colorado, and Wyoming, while 3 gross (2.5 net) development wells were in various stages of drilling and completion in Canada. The investment in the exploratory wells in progress was approximately $10 million at December 31, 2002.

OTHER PROPERTIES

The Company leases its corporate office facilities in Denver, Colorado. The lease covers approximately 56,500 square feet and expires January 31, 2004. Of this amount, the Company subleases 7,246 square feet under an agreement that expires January 31, 2004.

The Company leases office facilities in Midland, Texas. The lease covers approximately 33,150 square feet for a term of five years and expires December 31, 2003.

The Company also leases office facilities in Calgary, Alberta. The lease covers approximately 14,600 square feet for a term of five years and expires August 31, 2004.

For a summary of the rental commitments associated with these leases, see Note 13 Commitments and Contingencies in the Notes to the Company's Consolidated Financial Statements.

ITEM 3. ***Legal Proceedings***

The Company is a defendant in several routine legal proceedings incidental to its business.

In addition to routine legal proceedings incidental to the Company's business, Rocno was a defendant in a complaint filed by the United States of America which, among other things, alleged that Rocno and approximately 117 other companies arranged for the disposal of "hazardous materials" (within the meaning of CERCLA) in Waller County, Texas (the "Sheridan Superfund Site"). Effective August 31, 1989, Rocno and thirty-six other defendants executed the Sheridan Site Trust Agreement (the "Trust") for the purpose of creating a trust to perform agreed upon remedial action at the Sheridan Superfund Site. In connection with the establishment of the Trust, the parties to the Trust agreed to the terms of a Consent Decree entered December 3, 1991 in the United States District Court, Southern District of Texas, Houston Division, Civil Action No. H-91-3529, pursuant to which the defendants joining the Consent Decree will carry out the clean-up plan prescribed by the Consent Decree. In December 2002, the EPA approved a change in the remedy that was originally selected for clean-up of the Sheridan Superfund Site by eliminating the biotreatment of site wastes prior to stabilization and capping of the wastes. The EPA is currently amending the Consent Decree to include the revised remedy. The estimate of the total clean-up cost under the revised remedy is approximately $14.3 million. Under terms of the Trust, each party is allocated a percentage of costs necessary to fund the Trust for clean-up costs. Rocno's proportionate share of the estimated clean-up costs is 0.33% or $47,200, of which $16,000 has been paid, and the remainder was accrued in the Company's consolidated financial statements. If the clean-up costs exceed the projected amount, Rocno will be required to pay its pro rata share of the excess clean-up costs.

The Company is also a party to an action brought in Sweetwater County, Wyoming by three overriding royalty interest owners seeking certification as a class of all non-governmental entities which are paid royalties or overriding royalties by the Company in Wyoming. This action

is one of more than a dozen virtually identical class action lawsuits filed in various Wyoming courts against producers and operators in Wyoming. The complaint alleges that the Company violated the Wyoming Royalty Payment Act (the "Act") by improperly deducting gas transportation costs in calculating royalties and overriding royalties on Wyoming production and by failing to properly itemize all deductions taken on its payee reports. The complaint does not allege specific money damages. The issue in the case is whether transportation of natural gas off the lease to market is deductible transportation or nondeductible gathering within the meaning of the Act. In January 2003, the Wyoming Supreme Court agreed to answer two certified questions in a separate lawsuit which are (1) what is meant by the term "gathering" as that term is employed in the Act in defining nondeductible "costs of production," and (2) when do the causes of action for recovery of the reporting penalty and for improper deductions under the Act accrue. Because of the preliminary nature of the proceedings, it is not possible to fully determine the ultimate loss exposure or probable outcome of this litigation.

ITEM 4. ***Submission of Matters to a Vote of Security Holders***

No matters were submitted to a vote of the Company's stockholders in the fourth quarter of the year ended December 31, 2002.

ITEM 4A. ***Executive Officers of the Registrant***

On January 19, 2001, Donald L. Evans, the Company's Chairman of the Board and Chief Executive Officer, resigned to accept an appointment as the Secretary of the U.S. Department of Commerce. The Company's Board of Directors elected James B. Wallace as the new Chairman of the Board and James D. Lightner to the additional position of Chief Executive Officer in 2001 following Mr. Evans' resignation. At the annual stockholder's meeting in May 2002, James D. Lightner was elected to replace Mr. Wallace as the new Chairman of the Board.

The executive officers of the Company on March 18, 2003 were as follows:

Name	Age	Position with Company
James D. Lightner	50	Chairman, Chief Executive Officer and President
Daniel G. Blanchard	42	Executive Vice President, Chief Financial Officer and Treasurer
Thomas W. Dyk	49	Executive Vice President and Chief Operating Officer
Peter R. Scherer	46	Executive Vice President
Bruce R. DeBoer	50	Vice President, General Counsel and Secretary
Douglas R. Harris	48	Vice President Operations
Rodney G. Mellott	45	Vice President Land and Business Development

Each executive officer is elected annually by the Company's Board of Directors to serve at the Board's discretion.

The following biographies describe the business experience of the Company's executive officers for at least the past five years.

James D. Lightner joined the Company in May 1999 as President. In January 2001, he was named Chief Executive Officer. He was appointed Chairman of the Board in May 2002. Mr. Lightner has been a member of the Board of Directors since 1999. He also serves as a member of the Executive Committee. Prior to joining Tom Brown, Mr. Lightner served as Vice President and General Manager of the Denver Division of EOG Resources from April 1989 through April 1999.

Daniel G. Blanchard joined the Company in July 1999 as Vice President and Chief Financial Officer and was subsequently named Executive Vice President and Treasurer. From January 1999 through May 1999, Mr. Blanchard served as Assistant Treasurer with Gulf Canada Resources. He served as Treasurer and Director of Corporate Development for Forest Oil Company from September 1994 through December 1998.

Thomas W. Dyk joined the Company in April 1998 as Executive Vice President and was subsequently named the Company's Chief Operating Officer in 1999. Prior to joining Tom Brown, Mr. Dyk served as Regional Vice President for the Rocky Mountain Division of Burlington Resources.

Peter R. Scherer joined the Company in 1982. He has held various positions, most recently Executive Vice President and General Manager of the Southern Region. Prior to joining Tom Brown, Mr. Scherer was employed by Amoco Oil and Gas Company.

Bruce R. DeBoer joined the Company in 1997 as Vice President, General Counsel and Secretary. Prior to joining Tom Brown, he served in a similar capacity for eight years with Presidio Oil Company.

Douglas R. Harris joined the Company in February 2001 as Vice President Operations. From February 1986 through January 2001, he served as Vice President Production for Burlington Resources Canada in Calgary.

Rodney G. Mellott joined the Company in December 1999 as Vice President Land and Business Development. Prior to joining Tom Brown, Mr. Mellott was employed for 15 years in various capacities by EOG Resources, Inc.

PART II

ITEM 5. *Market for Registrant's Common Equity and Related Stockholder Matters*

The Company's Common Stock is listed and principally traded on the New York Stock Exchange ("NYSE") under the ticker symbol "TBI". Prior to May 16, 2002, the Company traded on the NASDAQ National Market System. The following table sets forth the range of high and low closing quotations for each quarterly period during the past two fiscal years as reported by NASDAQ National Market System for the March 31, 2001 through the March 31, 2002 periods, and the NYSE for the June 30, 2002 through December 31, 2002 period.

	Closing Sale Price	
Quarter Ended	**High**	**Low**
March 31, 2001	$ 35.25	$ 29.56
June 30, 2001	32.99	23.34
September 30, 2001	27.45	20.16
December 31, 2001	27.46	20.20
March 31, 2002	27.84	23.62
June 30, 2002	29.53	26.56
September 30, 2002	27.60	21.11
December 31, 2002	26.70	22.05

On March 11, 2003 the last sale price of the Company's Common Stock, as reported by the New York Stock Exchange was $24.75 per share.

The transfer agent for the Company's Common Stock is EquiServe Trust Company, N.A., Canton, Massachusetts.

On December 31, 2002, the outstanding shares of the Company's Common Stock (39,261,191 shares) were held by approximately 1,763 holders of record.

The Company has never declared or paid any cash dividends to the holders of Common Stock and has no present intention to pay cash dividends to the holders of Common Stock in the future. Under the terms of the Company's Credit Agreement, the Company is prohibited from paying cash dividends to the holders of Common Stock without the written consent of the bank lenders.

In January 1996, in connection with the acquisition of KN Production Company ("KNPC"), the Company issued 1,000,000 shares of its $1.75 Convertible Preferred Stock, Series A (the "Preferred Stock") to the seller. The Preferred Stock was exchangeable, in whole or in part, at the option of the Company on any dividend payment date at any time on or after March 15, 1999, and prior to March 15, 2001, for shares of Common Stock at the exchange rate of 1.666 shares of Common Stock for each share of Preferred Stock; provided that (i) on or prior to the date of exchange, the Company shall have declared and paid or set apart for payment to the holders of Preferred Stock all accumulated and unpaid dividends to the date of exchange, and (ii) the current market price of the Common Stock was above $18.375 (the "Threshold Price"). On June 15, 2000, the Company elected to exchange 1,666,000 shares of its Common Stock for all 1,000,000 outstanding shares of the Preferred Stock as the Common Stock had traded above the Threshold Price.

In July 1999, the Company completed an acquisition of substantially all of the Rocky Mountain oil and gas assets of Unocal Corporation for 5.8 million shares of common stock and $5 million in cash.

On March 1, 1991, the Board of Directors adopted a Rights Plan designed to help assure that all stockholders receive fair and equal treatment in the event of a hostile attempt to take over the Company, and to help guard against abusive takeover tactics. The Board of Directors declared a dividend of one preferred share purchase right (a "Right") for each outstanding share of Common Stock. The dividend was distributed on March 15, 1991 to the stockholders of record on that date. As of March 1, 2001, the Board of Directors amended and restated the Rights Plan. Each Right entitles the registered holder to purchase, for the $120 per share exercise price, shares of Common Stock or other securities of the Company (or, under certain circumstances, of the acquiring person) worth twice the per share exercise price of the Right.

The Rights will be exercisable only if a person or group acquires 15% or more of the Company's Common Stock or announces a tender offer which would result in ownership by a person or group of 15% or more of the Common Stock. The date on which the above occurs is to be known as the "Distribution Date". The Rights will expire on March 1, 2011, unless extended or redeemed earlier by the Company.

At the time the Rights dividend was declared, the Board of Directors further authorized the issuance of one Right with respect to each share of the Company's Common Stock that shall become outstanding between March 15, 1991 and the earlier of the Distribution Date or the expiration or redemption of the Rights. Until the Distribution Date occurs, the certificates representing shares of the Company's Common Stock also evidence the Rights. Following the Distribution Date, the Rights will be evidenced by separate certificates.

The provisions described above may tend to deter any potential unsolicited tender offers or other efforts to obtain control of the Company that are not approved by the Board of Directors and thereby deprive the stockholders of opportunities to sell shares of the Company's Common Stock at prices higher than the prevailing market price. See "Risk Factors." On the other hand, these provisions will tend to assure continuity of management and corporate policies and to induce any person seeking control of the Company or a business combination with the Company to negotiate on terms acceptable to the then elected Board of Directors.

ITEM 6. ***Selected Financial Data***

The following tables set forth selected financial information for the Company for each of the years shown.

The Company's historical results of operations have been materially affected by the increase in the Company's size as a result of the Stellarton Acquisition in January 2001 and the Unocal Acquisition in July 1999. (See the Notes to Consolidated Financial Statements of the Company included elsewhere herein.)

	Years Ended December 31,				
	2002	2001	2000	1999	1998
	(In thousands, except per share amounts)				
Revenues	$ 235,645	$ 326,324	$ 253,910	$ 123,411	$ 89,939
Income (loss) before cumulative effect of change in accounting principle(1)	9,926	67,477	65,703	5,007	(45,233)
Net (loss) income attributable to common stock	(8,177)	69,503	65,703	5,007	(45,233)
Weighted average number of common shares outstanding					
Basic	39,217	38,943	36,664	32,228	29,251
Diluted	40,327	40,227	37,897	32,466	29,251

	Years Ended December 31,				
Net (loss) income per common share					
Basic	(.21)	1.78	1.79	..16	(1.55)
Diluted	(.20)	1.73	1.76	..15	(1.55)
Total assets	850,952	844,975	629,535	536,299	441,882
Long-term debt, net of current maturities	133,172	120,570	54,000	81,000	55,000
Other Financial Data:					
Net cash provided by operating activities	121,562	207,900	132,958	38,857	60,100
Net cash used in investing activities	(137,171)	(276,987)	(117,738)	(54,999)	(89,634)
Net cash provided by (used in) financing activities	13,972	66,975	(10,196)	25,982	25,667

(1) Income (loss) in 2000, 1999 and 1998 shown net of the preferred dividends paid in these periods of $875,000, $1,750,000 and $1,750,000, respectively.

The following tables set forth selected information for the Company's gas and oil sales volumes and the proved reserves for each of the years shown.

	Years Ended December 31,				
	2002	2001	2000	1999	1998
Volumes sold:					
Gas (Mmcf)	72,167	63,824	51,199	40,514	35,887
Oil (MBbls)	843	881	773	910	1,027
Natural Gas Liquids (MBbls)	1,382	1,217	1,074	535	
Proved reserves at period end:					
Gas (Mmcf)	674,037	641,579	535,373	445,933	372,022
Oil (MBbls)	6,025	6,647	6,116	6,735	5,682
Natural Gas Liquids (MBbls)	6,655	8,360	5,077	6,266	

ITEM 7. ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The discussion and analysis of the Company's financial condition and results of operations was based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires the Company to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. The Company's significant accounting policies are described in the notes to our consolidated financial statements. The Company has identified certain of these policies as being of particular importance to the portrayal of the Company's financial position and results of operations and which require the application of significant judgment by management. The Company analyzes its estimates, including those related to the accounting for oil and gas revenues, bad debts, oil and gas properties, marketable securities, income taxes, derivatives, contingencies and litigation, and bases its estimates on historical experience and various other assumptions that the Company believes to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. The Company believes the following critical accounting policies relate to the more significant judgments and estimates used in the preparation of the Company's financial statements:

Successful Efforts Method of Accounting

The Company accounts for its natural gas and crude oil exploration and development activities utilizing the successful efforts method of accounting. Under this method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Gas and oil lease acquisition costs are also capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for gas and oil leases, are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities. The sale of a partial interest in a proved property is accounted for as a cost recovery and no gain or loss is recognized as long as this treatment does not significantly affect the unit-of-production amortization rate. A gain or loss is recognized for all other sales of producing properties.

The application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as developmental or exploratory which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Wells may be completed that are assumed to be productive and actually deliver gas and oil in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. Wells are drilled that have targeted geologic structures that are both developmental and exploratory in nature and an allocation of costs is required to properly account for the results. The evaluation of gas and oil leasehold acquisition costs requires judgment to estimate the fair value of these costs with reference to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

The successful efforts method of accounting can have a significant impact on the operational results reported when the Company is entering a new exploratory area in hopes of finding a gas and oil field that will be the focus of future development drilling activity. Any initial exploratory wells that are unsuccessful are expensed. Seismic costs can be substantial which will result in additional exploration expenses when incurred.

Reserve Estimates

The Company's estimates of gas, oil and natural gas liquids reserves, by necessity, are projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of gas and oil and the recovery factor for each accumulation, both of which are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable gas, oil and natural gas liquids reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area, the assumed effects of regulations by governmental agencies and assumptions governing future gas, oil and natural gas liquids prices, future operating costs, severance taxes, development costs and workover costs, all of which may in fact vary considerably from actual results. The future drilling costs associated with reserves assigned to proved undeveloped locations may ultimately increase to an extent that these reserves may be later determined to be uneconomic. For these reasons, estimates of the economically recoverable quantities of gas, oil and natural gas liquids attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows expected therefrom may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of the Company's gas and oil properties and/or the rate of depletion of the gas and oil properties. Actual production, revenues and expenditures with respect to the Company's reserves will likely vary from estimates, and such variances may be material.

Impairment of Gas and Oil Properties

The Company reviews its gas and oil properties for impairment whenever events and circumstances indicate a decline in the recoverability of their carrying value. The Company estimates the expected undiscounted future cash flows of its gas and oil properties and compares such future cash flows to the carrying amount of the gas and oil properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will adjust the carrying amount of the gas and oil properties to their fair value. The factors used to determine fair value include estimates of proved reserves, future commodity pricing, future production estimates,

anticipated capital expenditures, and a discount rate commensurate with the risk associated with realizing the expected cash flows projected. There were no impairments of producing gas and oil properties in 2002, 2001 or 2000.

Given the complexities associated with gas and oil reserve estimates and the history of price volatility in the gas and oil markets, events may arise that would require the Company to record an impairment of the recorded book values associated with gas and oil properties. In 1998, the Company recognized an impairment of $51.3 million primarily as a result of the low market prices in effect at that time; similar impairments may be required in the future. See "Risk Factors."

Derivative Instruments and Hedging Activities

The Company periodically hedges a portion of its gas and oil production through swap and collar agreements. The purpose of the hedges is to provide a measure of stability to the Company's cash flows in an environment of volatile gas and oil prices and to manage the exposure to commodity price risk. The Company recognizes all derivative instruments as assets or liabilities in the balance sheet at fair value. For cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. For derivative instruments that do not qualify as hedges, changes in fair value are recognized in earnings currently.

The estimation of fair values for the Company's hedging derivatives requires substantial judgment. The fair values of the Company's derivatives are estimated on a monthly basis using an option-pricing model. The option-pricing model uses various factors that include closing exchange prices on the NYMEX, over-the-counter quotations, volatility and the time value of options. These pricing and discounting variables are sensitive to market volatility as well as changes in future price forecasts, regional price differentials and interest rates.

RESULTS OF OPERATIONS

The following analysis of operations for the years ended December 31, 2002, 2001 and 2000 should be read in conjunction with the Consolidated Financial Statements and associated footnotes included in this 10-K.

The Company operates in three segments: (i) gas and oil exploration and development in the United States and Canada, (ii) marketing, gathering and processing and (iii) drilling. The revenue and segment profit attributable to each reportable segment are set forth in Note 12 Segment Information in the Notes to the Company's Consolidated Financial Statements. The factors that individually influenced the reported results of each of these business segments are set forth below.

Excluding the cumulative effect of changes in accounting principles, the Company realized net income for the year ended December 31, 2002 of $9.9 million or $.25 per share (diluted basis) as compared to net income of $67.5 million or $1.68 per share (diluted basis) for the same period in 2001. The majority of this decrease was attributable to lower commodity prices in 2002. The Company realized net income of $65.7 million or $1.76 per share (diluted basis) in the year ended December 31, 2000. The majority of the Company's production is natural gas and these general earnings trends were impacted significantly by the natural gas prices in effect each of these periods. The average realized natural gas price for 2002, 2001 and 2000 was $2.19 per Mcf, $3.71 per Mcf and $3.46 per Mcf, respectively.

The net loss and net income recognized in the years ended December 31, 2002 and 2001 were both impacted by the adoption of new accounting principles during these periods. On January 1, 2002, the Company adopted the new accounting standard SFAS No. 142 "Goodwill and Other Intangible Assets" (SFAS No. 142). The Company conducted a fair value based test effective January 1, 2002 to evaluate the goodwill originally recorded in conjunction with the January 2001 Stellarton Energy Corporation acquisition. The fair value of the reporting unit was determined with reference to the estimated discounted future net revenues of the underlying gas and oil reserves as of the date of the test and other financial considerations including going-concern value. This test resulted in the Company recording a non-cash charge of $18.1 million in the quarter ended March 31, 2002. The year ended December 31, 2001 was similarly impacted by the adoption of SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities effective January 1, 2001 for which a $2.0 million gain (net of tax) was recognized.

Revenues

During 2002, revenues from gas, oil and natural gas liquids production decreased 29% to $194.3 million, as compared to $274.0 million in 2001. This decrease was the result of (i) a decrease in average gas prices realized by the Company from $3.71 per Mcf in 2001 to $2.19 per Mcf in 2002, which decreased revenues $109.7 million, (ii) a decrease in average oil and natural gas liquids prices received from $17.86 to $16.35 which decreased revenues $3.4 million partially offset by, (iii) an increase in gas sales volumes of 13% to 72 Bcf which increased revenues by $31.0 million, and (iv) an increase in oil and natural gas liquids sales volumes of 6% to 2.2 million barrels, which increased revenues by $2.4 million.

Revenues in 2002 were not materially impacted by hedging activities.

During 2001, revenues from gas, oil and natural gas liquids production increased 26% to $274.0 million, as compared to $217.0 million in 2000. This increase was the result of (i) an increase in average gas prices received by the Company from $3.46 per Mcf in 2000 to $3.71 per Mcf in 2001, which increased revenues $16.0 million, (ii) a decrease in average oil and natural gas liquids prices received from $21.49 to $17.86 which decreased revenues $7.6 million, (iii) an increase in gas sales volumes of 25% to 63.8 Bcf which increased revenues by $43.7 million, and (iv) an increase in oil and natural gas liquids sales volumes of 14% to 2.1 million barrels, which increased revenues by $4.9 million.

Revenues in 2001 were also impacted by cash gains realized from hedging activities. The NYMEX collar and swap transactions considered effective hedges and settled in 2001, resulted in realized gains of $15.9 million, which were included in gas and oil sales. There was no material hedging activity in 2000.

The revenues contributed by the Stellarton transaction for the period subsequent to the closing date of January 12, 2001 were $30.1 million in 2001 and $27.8 million in 2002.

The following table reflects the Company's revenues, average prices received for gas and oil, and amount of gas and oil production in each of the years shown:

	Years Ended December 31,		
	2002	2001	2000
	(In thousands)		
Revenues:			
Natural gas sales	$ 157,881	$ 236,551	$ 177,267
Crude oil sales	19,733	20,350	21,686
Natural gas liquids	16,662	17,130	18,015
Gathering and processing	20,467	23,245	18,283
Marketing and trading, net	5,276	1,891	5,841
Drilling	14,347	14,828	11,472
Cash (paid) received on derivatives	(2,061)	4,121	
Change in derivative fair value	(345)	(3,224)	
Gain on sale of property	4,114	10,078	
Interest income and other	(429)	1,354	1,346
Total revenues	$ 235,645	$ 326,324	$ 253,910

	Years Ended December 31,		
	2002	2001	2000
Natural gas production (Mmcf)	72,167	63,824	51,199
Crude oil production (MBbls)	843	881	773
Natural gas liquid production (MBbls)	1,382	1,217	1,074
Average natural gas sales price ($/Mcf)	$ 2.19	$ 3.71	$ 3.46
Average crude oil sales price ($/Bbl)	$ 23.41	$ 23.09	$ 28.05
Average natural gas liquid sales price ($/Bbl)	$ 12.05	$ 14.07	$ 16.77

Gathering and processing revenues decreased 12% to $20.5 million in 2002 compared to $23.2 million in 2001. A number of non-strategic gathering and processing assets were sold throughout 2001 resulting in the decrease in gathering and processing revenue in 2002. In 2001, gathering and processing revenue increased 27% to $23.2 million, as compared to $18.3 million in 2000. This increase was attributable to the distribution of certain gathering and processing assets to the Company from Wildhorse Energy Partners, LLC ("Wildhorse") in November 2000. Incremental revenues were recognized in 2001 as a result of the 100% ownership of these gathering and processing assets which previously were 45% owned by the Company through the Wildhorse partnership.

Net marketing and trading income increased to $5.3 million in 2002 from a net margin of $1.9 million in 2001 and $5.8 million in 2000. Income increased in 2002 due to the Company transporting gas into the Mid Continent region to take advantage of higher gas prices in this

market. Net marketing and trading income has increased principally as a result of this marketing opportunity that utilized the Company's firm transportation. Although this marketing differential increased marketing and trading income, the Company had previously entered into certain financial instruments to lock the basis differential for the June through October contract periods in the Mid Continent market. As these financial instruments were considered trading derivatives under SFAS No. 133, the cash settlements of $2.1 million in 2002 were recognized as derivative losses during the year ended December 31, 2002. The cash profits realized on the physical sales included in marketing and trading income were partially offset by the $2.1 million cash settlement on the trading derivatives. However, the net impact of these transactions for 2002 was that the Company was successful in realizing an additional $.29 Mmbtu margin (after transportation costs) on gas moved into the Mid Continent region. The marketing and trading margins in 2000 benefited from certain term and spot marketing arrangements at more favorable terms than were available in the 2001 market.

Drilling revenue associated with the Company's wholly-owned subsidiary, Sauer, remained relatively unchanged in 2002 at $14.3 million. In 2002 Sauer generated a higher percentage of its contract drilling revenue from third-party contracts not affiliated with Tom Brown. Contract drilling revenues associated with wells operated by the Company and drilled by Sauer are eliminated in consolidation. This change in mix for 2002 resulted in essentially equivalent drilling revenues for 2002 and 2001 despite a decrease in the rig utilization rates from over 90% in 2001 to approximately 70% in 2002. Drilling revenue increased from $11.5 million in 2000 to $14.8 million in 2001 due to higher rig utilization rates and increased day rates resulting from the general increase in activity within the oil and gas industry in 2001 as compared to 2000.

Costs and Expenses

Expenses related to gas and oil production remained flat from 2001 to 2002. On an Mcfe basis, gas and oil production costs decreased to $.38 in 2002 from $.42 in 2001 as a result of a continued focus on cost containment.

Expenses related to gas and oil production increased 26% from 2000 to 2001 due primarily to the Stellarton acquisition and increased production levels in 2001. On an Mcfe basis, gas and oil production costs remained relatively flat at $.42 in 2001 and $.41 in 2000.

Taxes on gas and oil production decreased by 21% or ($4.4 million) in 2002 primarily due to a 29% or ($80 million) decrease in revenue from gas, oil and natural gas liquids from 2001 due to lower natural gas and natural gas liquids commodity prices.

Taxes on gas and oil production decreased by 5% or ($1.1 million) in 2001 despite a 26% or ($57 million) increase in revenue from gas, oil and natural gas liquids for 2001. This resulted from the inclusion of $30.1 million of Canadian revenues in the 2001 results which are not subject to severance and other taxes typically incurred in the United States. Additionally, $15.9 million realized on the natural gas hedge transactions was included in gas and oil sales in 2001 which is not subject to production related taxes. The Company also obtained a refund in 2001 of a portion of the production taxes paid in prior years which reduced the expenses reported.

Depreciation, depletion and amortization increased $16.9 million in 2002 as compared to 2001. The production increase of 12% on a Mcfe basis for 2002 contributed $8.8 million to the increased depreciation, depletion and amortization. The Company's per unit depletion rate also increased in 2002 as a result of higher finding costs on the gas and oil reserve additions associated with the 2002 and 2001 capital programs. In 2002, depreciation, depletion and amortization expense on the producing gas and oil properties was $.95 per Mcfe as compared to $.83 per Mcfe in 2001.

Depreciation, depletion and amortization increased $24.0 million in 2001 as compared to 2000. Approximately $14.1 million of this increase was associated with the depletion recorded on the Stellarton assets acquired in January 2001. The production increase of 9% on a Mcfe basis on the domestic properties for 2001 also increased depreciation, depletion and amortization.

Gathering and processing costs principally represent costs associated with operating and maintaining the field systems. The $3.9 million decrease in gathering and processing costs for 2002 was caused by the Company's disposition of a number of the gathering and processing assets in 2001 which were considered non-strategic to the Company's operations.

Expenses associated with the Company's exploration activities were $22.8 million, $34.2 million and $11.0 million for the years 2002, 2001 and 2000, respectively. Exploration expense for these periods was impacted by the dry hole costs of $7.8 million, $15.8 million and $1.2 million recognized in 2002, 2001 and 2000, respectively. The Company also incurred additional seismic costs in 2001 which were primarily associated with the James Lime and Deep Valley projects in Texas that contributed to the increased exploration expense incurred in that period. Capital expenditures of $161.7 million were incurred in 2002 compared to $358.1 million in 2001, which included $95 million associated with the Stellarton Acquisition. The 2002 exploration, development and land related expenditures were $139 million, a decrease of 43% in comparison to 2001. In 2000, the exploration, development and land related expenditures were $109.6 million. The Company's capital program budgets are influenced by the gas and oil prices received for its production. The exploration expenses recognized by the Company are influenced by the magnitude of the capital expenditures incurred in each year. Capital programs are risk adjusted to balance exploration and development opportunities.

Recurring general and administrative expenses have increased from year to year as a result of the Company's increased level of operations. On an Mcfe basis, general and administrative expenses were $.22, $.30, and $.19 for the years 2002, 2001 and 2000, respectively. Included in the expenses for 2001 was a $5.3 million ($.07 per Mcfe) pre-tax charge recorded in the first quarter of 2001 associated with the retirement of Donald L. Evans, the Company's former Chairman and CEO. Mr. Evans received a $1.5 million retirement payment and the Company recognized a $3.8 million non-cash charge in conjunction with the acceleration of Mr. Evans' stock options. General and administrative expenses related to the new Canadian operations contributed $2.0 million ($.02 per Mcfe) to the increase in 2002 and $2.5 million ($.03 per Mcfe) for 2001. Expenses also increased due to the addition of personnel necessary to implement the increased capital expenditure programs in 2001 and 2002.

Bad debt expense increased in 2002 as a result of a default by a previous purchaser of the Company's natural gas liquids in the Paradox Basin of Colorado and Utah on payments owed the Company totaling $6.2 million. An allowance for this entire receivable was recorded in the third quarter of 2002 given the uncertainty of collection at that time. The Company continued to aggressively pursue recovery of the amount owed and in the fourth quarter of 2002, a $1.4 million settlement was received in cash. The collection of this settlement was treated as an adjustment to the allowance originally recorded. As of December 31, 2002, the Company does not anticipate that any future settlements will be received that will materially reduce the loss recognized as a result of this purchaser's default.

Interest and other expense in 2002 was impacted by standby fees incurred under the terms of a two-year commitment for a drilling rig utilized by the Company at the Deep Valley project in West Texas. This rig became available in 2002 and $1.6 million of standby fees were charged to expense when the rig was not being utilized. Interest expense also increased in 2001 and 2002 after the Stellarton acquisition in January 2001 for which $95 million in debt was incurred. The Company's effective interest rate under its credit facility was 3.9% at December 31, 2002 and 4.1% at December 31, 2001.

The Company recorded income tax provisions of $3.2 million, $38.1 million and $39.8 million in 2002, 2001, and 2000, respectively, resulting in effective tax rates of 24.4%, 36.1% and 37.4%, respectively. The 2002 income tax provision of $3.2 million was impacted by a $1.6 million tax reduction associated with certain Canadian expenses deductible in the United States and by $0.7 million in state tax credits associated with drilling incentives in Colorado and Utah. There was no tax impact associated with the goodwill impairment recorded in conjunction with the change in accounting principle as goodwill is not considered a deductible expense for tax purposes. At December 31, 2002, the Company has a net operating loss carryforward available for U.S. Federal tax purposes of $25.9 million and a net operating loss carryforward available to reduce future Canadian federal income taxes of $6.0 million ($9.4 million CDN). Additionally, statutory depletion carryforwards of approximately $7.2 million and $4.8 million of alternative minimum tax credit carryforwards are available in the U.S. to offset future taxes. Based upon the operating results for 2002 and the present economic environment for the gas and oil industry, the Company believes that it will generate sufficient taxable income to utilize these carryforwards.

CAPITAL RESOURCES AND LIQUIDITY

Growth and Acquisitions

The Company continues to pursue opportunities which will add value by economically increasing its reserve base and presence in significant natural gas areas, and further developing the Company's ability to control and market the production of natural gas. As the Company continues to evaluate potential acquisitions and property development opportunities, it will benefit from its financing flexibility and the leverage potential of the Company's overall capital structure.

Capital and Exploration Expenditures

The Company's capital and exploration expenditures and sources of financing for the years ended December 31, 2002, 2001 and 2000 are as follows:

	2002	2001	2000
		(In millions)	
CAPITAL AND EXPLORATION EXPENDITURES:			
ACQUISITIONS:			
Stellarton	$	$ 95.0	$
Rocky Mountain assets and other	15.9	3.3	17.1
Exploration costs	33.2	56.0	18.4
Development costs	94.6	163.2	74.4
Acreage	10.9	22.6	16.8
Gas gathering and processing	4.7	9.3	16.3

	2002	2001	2000
Sauer Drilling Company	.9	5.2	2.7
Other	1.5	3.5	4.8
	$ 161.7	$ 358.1	$ 150.5
FINANCING SOURCES:			
Common stock issued	$ 2.2	$ 11.2	$ 17.7
Net long term bank debt	11.8	55.8	(27.0)
Debt assumed on Stellarton transaction		16.8	
Proceeds from sale of assets	10.8	52.4	9.7
Cash flow provided by operating activities	121.6	207.9	133.0
Other	15.3	14.0	17.1
	$ 161.7	$ 358.1	$ 150.5

The Company anticipates capital and exploration expenditures between $155 to $185 million in 2003, approximately 90% of which will be allocated to exploration and development activity. The timing of most of the Company's capital expenditures is discretionary and there are no material long-term commitments associated with the Company's capital expenditure plans. Consequently, the Company is able to adjust the level of its capital expenditures as circumstances warrant. The level of capital expenditures by the Company will vary in future periods depending on energy market conditions and other related economic factors.

Historically, the Company has funded capital expenditures and working capital requirements with both internally generated cash, borrowings and stock transactions.

Property Sales

In April 2002, the Company sold its interest in oil and gas properties located in the Powder River Basin of Wyoming to an unrelated third party for net cash proceeds of $7.2 million. These properties had a net book value of $3.1 million, which resulted in a $4.1 million gain on the sale.

In April 2002, the Company also sold certain oil and gas properties located primarily in Louisiana to an unrelated third party for $2.0 million. In November 2002, the Company sold certain oil and gas properties located in Colorado to an unrelated third party for $1.6 million. As these sales represented partial interests in these proved properties, the proceeds were recorded as a reduction to the recorded cost of the oil and gas properties.

In 2001, $52.4 million in cash proceeds were derived from property sales. In May 2001, the Company sold its interest in gas and oil properties located in Oklahoma to an unrelated third party. These properties had a net book basis of $14.4 million. This transaction resulted in a gain of $10.1 million with net cash proceeds of $24.5 million. Cash proceeds of $24 million were also realized in conjunction with several sales transactions in 2001 associated with the disposition of gathering and processing facilities received in the Wildhorse distribution in November 2000. As the systems sold were non-strategic to the Company's operations and these divestitures were anticipated as part of the Wildhorse integration process, the proceeds derived on these transactions were recorded as a reduction to the investment in the gathering assets.

Debt

Contractual Obligations

In addition to the bank credit facility discussed in the following note, the Company had various other contractual obligations as of December 31, 2002. The Company has no off-balance sheet debt or other such unrecorded obligations and the Company has not guaranteed the debt of any other party. The following table lists the Company's significant liabilities at December 31, 2002 including the credit facility:

	Payments Due by Period				
Contractual Obligations	**Less than 1 year**	**2-3 Years**	**4-5 Years**	**After 5 Years**	**Total**

	Payments Due by Period				
	(In thousands)				
Bank credit facility	$	$ 38,172	$ 95,000	$	$ 133,172
Operating leases	1,639	494	49		2,182
Transportation commitments	5,274	6,386	1,420	228	13,308
Processing commitment	2,640	5,280	5,280	10,560	23,760
Drilling rig obligation	7,337	2,995			10,332
Total contractual cash obligations	$ 16,890	$ 53,327	$ 101,749	$ 10,788	$ 182,754

The Company leases its corporate office in Denver, Colorado under the terms of an operating lease, which expires in January 2004. Yearly payments under the lease are approximately $1,061,000 net of sublease income. The Company's offices in Midland, Texas represents a commitment of $215,000 per year through December 2003 and the office lease in Calgary, Alberta expires in August 2004 at a rate of $152,000 per year. The remaining operating lease commitments represent equipment leases, which expire during 2002 through 2008.

The Company has entered into various firm transportation commitments for approximately 56.8 Mmcf of gross gas sales per day as of December 31, 2002. The majority of these contracts expire in 2003 through 2006. Subsequent to December 31, 2002, the Company entered into additional firm transportation commitments on approximately 29 Mmcf of gross gas sales per day under varying terms that expire in 2008 and 2011. These 2003 commitments totaled $19.6 million and are not included in the above schedule.

On December 31, 2001, the Company entered into an agreement with an unrelated third party to process its gas production from the White River Dome coal bed methane project in the Piceance Basin. Under the terms of this agreement, the Company is obligated to pay the third party $220,000 per month over the ten year term to cover the fixed operating costs of the plant and provide for a recovery of the plant investment to the third party. The Company is also obligated to reimburse the third party for certain variable expenses associated with the volumes processed through the plant and for compression made available to the Company. The Company has the right but not the obligation to purchase the processing facility from the third party during the term of this agreement upon 60 days prior written notice of its election to purchase the facilities.

To assure the availability of a drilling rig in conjunction with an exploration program in west Texas, the Company entered into a two-year commitment with a drilling contractor in 2001. The rig became available in 2002 and the two-year drilling obligation commenced on May 29, 2002. Under the terms of this arrangement, the Company is required to pay a day rate of $20,100 per day during drilling operations and $16,700 per day for rig moves.

Bank Credit Facility

On June 30, 2000, the Company entered into a $125 million credit facility (the "Credit Facility") that was to mature in June 2003. Under the terms of the Credit Facility, the borrowing base was established at $225 million.

On March 20, 2001, as part of the final financing of the Stellarton acquisition, the Company repaid and cancelled its previous $125 million Credit Facility and entered into a new $225 million credit facility (the "Global Credit Facility"). The Global Credit Facility is comprised of: a $75 million line of credit in the U.S. and a $55 million line of credit in Canada which both mature in March 2004, and a $95 million five-year term loan in Canada. The borrowing base under the Global Credit Facility was set at $300 million. The Global Credit Facility allows the lenders one scheduled redetermination of the borrowing base each December. In addition, the lenders may elect to require one unscheduled redetermination in the event the borrowing base utilization exceeds 50% of the borrowing base at any time for a period of 15 consecutive business days. At December 31, 2002, the Company had borrowings outstanding under the Global Credit Facility totaling $133.2 million or 44% of the borrowing base at an average interest rate of 3.9% The amount available for borrowing under the Global Credit Facility at December 31, 2002 was $91.8 million.

Borrowings under the Global Credit Facility are unsecured and bear interest, at the election of the Company, at a rate equal to (i) the greater of the global administrative agents prime rate or the federal funds effective rate plus an applicable margin, (ii) adjusted LIBOR for Eurodollar loans plus applicable margin, or (iii) Bankers' Acceptances plus applicable margin for Canadian dollar loans. Interest on amounts outstanding under the Global Credit Facility is due on the last day of each quarter for prime based loans, and in the case of Eurodollar loans with an interest period of more than three months, interest is due at the end of each three month interval.

The Global Credit Facility contains certain financial covenants that require the Company to maintain a minimum consolidated tangible net worth of not less than $350 million (adjusted upward by 50% of quarterly net income subsequent to March 31, 2001 and 50% of the net cash proceeds of any stock offering). The Company must also maintain a ratio of indebtedness to earnings before interest expense, state and federal

taxes and depreciation, depletion and amortization expense and exploration expense of not more than 3.0 to 1.0 as calculated at the end of each fiscal quarter. The Company was in compliance with all covenants during 2002 and at December 31, 2002.

MARKETS AND PRICES

The Company's revenues and associated cash flows are significantly impacted by changes in gas and oil prices. All of the Company's gas and oil production is currently market sensitive as none of the Company's gas and oil production has been presold at contractually specified prices. During 2002, the average prices received for gas and oil by the Company were $2.19 per Mcf and $16.35 per barrel, respectively, as compared to $3.71 Mcf and $17.86 per barrel in 2001 and $3.46 per Mcf and $21.49 per barrel in 2000.

APPLICATION OF RECENTLY ISSUED ACCOUNTING STANDARDS ON INTANGIBLE ASSETS

In connection with a review of the Company's financial statements by the staff of the Securities and Exchange Commission, the Company has been made aware that an issue has arisen within the industry regarding the application of provisions of Statement of Financial Accounting Standards No. 141, "Business Combinations," and Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142), to companies in the extractive industries, including gas and oil companies. The issue is whether SFAS No. 142 requires registrants to reclassify costs associated with mineral rights, including both proved and unproved leasehold acquisition costs, as intangible assets in the balance sheet, apart from other capitalized gas and oil property costs. Historically, the Company and other gas and oil companies have included the cost of these gas and oil leasehold interests as part of gas and oil properties. Also under consideration is whether SFAS No. 142 requires registrants to provide the additional disclosures prescribed by SFAS No. 142 for intangible assets for costs associated with mineral rights.

If it is ultimately determined that SFAS No. 142 requires the Company to reclassify costs associated with mineral rights from property and equipment to intangible assets, the amounts that would be reclassified are as follows:

	December 31,	
	2002	**2001**
	(In thousands)	
INTANGIBLE ASSETS:		
Proved leasehold acquisition costs	$ 340,058	$ 315,530
Unproved leasehold acquisition costs	62,645	76,384
Total leasehold acquisition costs	402,703	391,914
Less: Accumulated depletion	107,158	84,076
Net leasehold acquisition costs	$ 295,545	$ 307,838

The reclassification of these amounts would not effect the method in which such costs are amortized or the manner in which the Company assesses impairment of capitalized costs. As a result, net income would not be affected by the reclassification.

ITEM 7A. ***Quantitative and Qualitative Disclosure About Market Risk***

COMMODITY PRICE FLUCTUTATIONS

The Company's results of operations are highly dependent upon the prices received for oil and natural gas production. Accordingly, in order to increase the financial flexibility and to protect the Company against commodity price fluctuations, the Company may, from time to time in the ordinary course of business, enter into hedging arrangements, including commodity swap agreements, forward sale contracts, commodity futures, options and other similar agreements relating to natural gas and crude oil expected to be produced. The Company has also entered into certain financial instruments that did not qualify as hedging arrangements. These transactions have principally involved basis contracts entered into to secure a pricing differential into markets where the Company has transportation agreements.

Financial instruments designated as hedges are accounted for on the accrual basis with gains and losses being recognized based on the type of contract and exposure being hedged. Gains and losses on natural gas and crude oil swaps designated as hedges of anticipated transactions,

including gains or losses recognized upon early termination of contracts, are deferred and recognized in income when the associated hedged commodities are produced. In order for natural gas and crude oil swaps or collars to qualify as a hedge of an anticipated transaction, the derivative contract must identify the expected date of the transaction, the commodity involved, and the expected quantity to be purchased or sold among other requirements. In the event that it becomes probable that a hedged transaction will not occur, gains and losses, including gains or losses upon early termination of contracts, are included in the income statement.

The Company has natural gas hedges, in the form of costless collars and swaps (including related basis swaps), as follows as of December 31, 2002:

	Natural Gas Collars		Natural Gas Swaps	
Period	**Mmbtu/d**	**Weighted Average Floor/Ceiling**	**Mmbtu/d**	**Weighted Average Swap Price**
First Quarter 2003	37,500	$3.82/5.01	80,000	$ 3.05
Second Quarter 2003	40,000	$3.37/4.65	57,500	$ 3.02
Third Quarter 2003	40,000	$3.37/4.65	55,800	$ 3.04
Fourth Quarter 2003	23,500	$3.27/4.61	19,000	$ 3.04

The Company also entered into certain financial instruments to lock the basis differential on 15,000 Mmbtu/day of firm transportation volumes during the June through October contract periods of 2002. These contracts effectively fixed a price differential into the Mid Continent market at a weighted average price of $0.78 above the price index for a delivery point in the Rocky Mountain area where the Company markets a significant portion of its natural gas production. Under SFAS 133, these basis swaps did not qualify for hedge accounting. Accordingly, these basis swaps resulted in the recognition of derivative losses of $2.1 million in 2002 which were recorded directly to earnings.

INTEREST RATE RISK

At December 31, 2002, the Company had $133.2 million outstanding under the Global Credit Facility at an average interest rate of 3.9%. Borrowings under the Global Credit Facility bear interest, at the election of the Company, at (i) the greater of the agent bank's prime rate or the federal funds effective rate, plus an applicable margin or (ii) the agent bank's Eurodollar rate, plus an applicable margin. As a result, the Company's annual interest cost in 2003 will fluctuate based on short-term interest rates. Assuming no change in the amount outstanding during 2003, the impact on interest expense of a ten percent change in the average interest rate would be approximately $.5 million. As the interest rate is variable and is reflective of current market conditions, the carrying value of the Global Credit Facility approximates the fair value.

FOREIGN CURRENCY EXCHANGE RISK

The Company conducts business in Canada where the Canadian dollar has been designated as the functional currency. This subjects the Company to foreign currency exchange risk on cash flows related to sales, expenses, financing and investing transactions. The Company has not entered into any foreign currency forward contracts or other similar financial instruments to manage this risk.

ITEM 8. ***Financial Statements and Supplementary Data***

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Independent Auditors' Report
Report of Independent Public Accountants
Consolidated Balance Sheets, December 31, 2002 and 2001
Consolidated Statements of Operations, Years ended December 31, 2002, 2001 and 2000
Consolidated Statements of Changes in Stockholders' Equity, Years ended December 31, 2002, 2001 and 2000
Consolidated Statements of Cash Flows, Years ended December 31, 2002, 2001 and 2000
Notes to Consolidated Financial Statements

Independent Auditors' Report

The Board of Directors and Stockholders
Tom Brown, Inc.:

We have audited the 2002 consolidated financial statements of Tom Brown, Inc. (a Delaware corporation) and subsidiaries as listed in the accompanying index. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit. The 2001 and 2000 consolidated financial statements of Tom Brown, Inc. and subsidiaries as listed in the accompanying index were audited by other auditors who have ceased operations. Those auditors' report, dated February 27, 2002, on those consolidated financial statement was unqualified and included an explanatory paragraph that described the change in the Company's method of accounting for derivative instruments and hedging activities discussed in Notes 2 and 9 to the consolidated financial statements.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America. 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 audit provides a reasonable basis for our opinion.

In our opinion, the 2002 consolidated financial statements referred to above present fairly, in all material respects, the financial position of Tom Brown, Inc. and subsidiaries as of December 31, 2002, and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed in Notes 2 and 3 to the consolidated financial statements, the Company changed its method of accounting for goodwill and other intangible assets in 2002, and as discussed in Notes 2 and 9 to the consolidated financial statements, the Company changed its method of accounting for derivative instruments and hedging activities in 2001.

KPMG LLP

Denver, Colorado
February 20, 2003

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

THE FOLLOWING REPORT IS A COPY OF THE PREVIOUSLY ISSUED REPORT FROM ARTHUR ANDERSEN LLP (ANDERSEN). ANDERSEN DID NOT PERFORM ANY PROCEDURES IN CONNECTION WITH THIS ANNUAL REPORT ON FORM 10-K NOR HAS ANDERSEN PROVIDED A CONSENT TO THE INCLUSION OF ITS REPORT IN THIS FORM 10-K. FOR FURTHER DISCUSSION, SEE EXHIBIT 23.2 TO THE FORM 10-K OF WHICH THIS REPORT FORMS A PART. ACCORDINGLY, THIS REPORT HAS NOT BEEN REISSUED BY ANDERSEN.

To the Board of Directors and Stockholders of Tom Brown, Inc.:

We have audited the accompanying consolidated balance sheets of Tom Brown, Inc. (a Delaware corporation) and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of operations, changes in stockholders' equity and cash flows for each of the three years in the period ended December 31, 2001. These financial statements 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 Tom Brown, Inc. and subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their 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.

As explained in Notes 2 and 10 to the consolidated financial statements, on January 1, 2001, the Company changed its method of accounting for derivative instruments and hedging activities.

ARTHUR ANDERSEN LLP

Denver, Colorado
February 27, 2002

TOM BROWN, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31,	
	2002	**2001**
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 13,555	$ 15,196
Accounts receivable, net of allowance for doubtful accounts	47,414	63,745
Inventories	1,808	1,689
Other	3,988	2,332
Total current assets	66,765	82,962
PROPERTY AND EQUIPMENT, AT COST:		
Gas and oil properties, successful efforts method of accounting	959,807	849,628
Gas gathering and processing and other plant	101,054	89,343
Other	35,930	33,689
Total property and equipment	1,096,791	972,660
Less: Accumulated depreciation, depletion and amortization	320,306	234,134
Net property and equipment	776,485	738,526
OTHER ASSETS:		
Goodwill, net		18,125
Other assets	7,702	5,362
	$ 850,952	$ 844,975
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 42,773	$ 59,172
Accrued expenses	21,993	12,512
Fair value of derivative instruments	10,886	
Total current liabilities	75,652	71,684

	December 31,	
BANK DEBT	133,172	120,570
DEFERRED INCOME TAXES	73,967	75,194
OTHER NON-CURRENT LIABILITIES	4,543	2,299
COMMITMENTS AND CONTINGENCIES (Note 13)		
STOCKHOLDERS' EQUITY:		
Convertible preferred stock, $.10 par value Authorized 2,500,000 shares; none issued		
Common Stock, $.10 par value Authorized 55,000,000 shares; Issued and outstanding 39,261,191 and 39,127,649 shares, respectively	3,926	3,913
Additional paid-in capital	537,449	534,790
Retained earnings	29,678	37,855
Accumulated other comprehensive loss	(7,435)	(1,330)
Total stockholders' equity	563,618	575,228
	$ 850,952	$ 844,975

See accompanying notes to consolidated financial statements.

TOM BROWN, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2002	2001	2000
	(In thousands, except per share amounts)		
REVENUES:			
Gas, oil and natural gas liquids sales	$ 194,276	$ 274,031	$ 216,968
Gathering and processing	20,467	23,245	18,283
Marketing and trading, net	5,276	1,891	5,841
Drilling	14,347	14,828	11,472
Gain on sale of properties	4,114	10,078	
Cash (paid) received on derivatives	(2,061)	4,121	
Change in derivative fair value	(345)	(3,224)	
Loss on marketable security	(600)		
Interest income and other	171	1,354	1,346
Total revenues	235,645	326,324	253,910
COSTS AND EXPENSES:			
Gas and oil production	32,151	32,060	25,488
Taxes on gas and oil production	16,621	21,020	22,105
Gathering and processing costs	6,918	10,855	7,212
Drilling operations	13,763	11,851	9,715
Exploration costs	22,824	34,195	11,001
Impairments of leasehold costs	5,564	5,236	3,900

	Years Ended December 31,		
General and administrative	18,413	22,742	11,614
Depreciation, depletion and amortization	91,307	74,371	50,417
Bad debts	5,222	1,043	133
Interest expense and other	9,726	7,347	5,967
Total costs and expenses	222,509	220,720	147,552
Income before income taxes and cumulative effect of change in accounting principle	13,136	105,604	106,358
Income tax provision			
Current	(229)	(1,200)	(1,968)
Deferred	(2,981)	(36,927)	(37,812)
Income before cumulative effect of change in accounting principle	9,926	67,477	66,578
Cumulative effect of change in accounting principle	(18,103)	2,026	
Net (loss) income	(8,177)	69,503	66,578
Preferred stock dividends			(875)
Net (loss) income attributable to common stock	$ (8,177)	$ 69,503	$ 65,703
Weighted average number of common shares outstanding:			
Basic	39,217	38,943	36,664
Diluted	40,327	40,227	37,897
Earnings per common share-Basic:			
Income before cumulative effect of change in accounting principle	$ .25	$ 1.73	$ 1.79
Cumulative effect of change in accounting principle	(.46)	.05	
Net (loss) income attributable to common stock	$ (.21)	$ 1.78	$ 1.79
Earnings per common share-Diluted:			
Income before cumulative effect of change in accounting principle	$ .25	$ 1.68	$ 1.76
Cumulative effect of change in accounting principle	(.45)	.05	
Net (loss) income attributable to common stock	$ (.20)	$ 1.73	$ 1.76

See accompanying notes to consolidated financial statements.

TOM BROWN, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

Preferred Stock		Common Stock		Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
Shares	Amount	Shares	Amount				

	Preferred Stock		Common Stock			Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	
					(In thousands)			
Balance as of December 31, 1999	1,000	$ 100	35,308	$ 3,531	$ 495,724	(97,351	93	$ 402,097
Stock options exercised			1,378	137	17,475	$)	$	17,612
Income tax benefit of stock options exercised					3,779			3,779
Preferred stock dividends						(875)		(875)
Preferred stock conversion	(1,000)	(100)	1,666	167	(67)			
Comprehensive income (loss):								
Unrealized loss on marketable securities							(298)	(298)
Net income						66,578		66,578
Total comprehensive income								66,280
Balance as of December 31, 2000			38,352	3,835	516,911	(31,648)	(205)	488,893
Stock options exercised			776	78	11,085			11,163
Income tax benefit of stock options exercised					2,897			2,897
Accelerated vesting of options					3,897			3,897
Comprehensive income (loss):								
Translation loss							(790)	(790)
Cumulative effect of change in accounting principle (net of tax)							(4,449)	(4,449)
Change in fair value of derivative hedging instruments							14,466	14,466
Settlements of derivative hedging instruments reclassified to income (net of tax)							(10,017)	(10,017)
Unrealized loss on marketable securities							(335)	(335)
Net income						69,503		69,503
Total comprehensive income								68,378
Balance as of December 31, 2001			39,128	3,913	534,790	37,855	(1,330)	575,228
Stock options exercised			133	13	2,145			2,158
Income tax benefit of stock options exercised					514		514	
Comprehensive income (loss):								
Translation loss							(80)	(80)
Unrealized loss on marketable securities reclassified to income							540	540
Change in fair value of derivative hedging instruments (net of tax)							(6,517)	(6,517)
Unrealized loss on marketable securities							(50)	(50)
Settlements of derivative hedging instruments reclassified to income (net of tax)							2	2
Net loss						(8,177)		(8,177)
Total comprehensive loss								(14,282)
Balance as of December 31, 2002		$	39,261	$ 3,926	$ 537,449	$ 29,678	$ (7,435)	$ 563,618

See accompanying notes to consolidated financial statements.

TOM BROWN, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2002	2001	2000
	(In thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net (loss) income	$ (8,177)	$ 69,503	$ 66,578
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Depreciation, depletion and amortization	91,307	74,371	50,417
Unrealized loss on derivatives	345		
Loss on marketable security	600		
Gain on sales of assets	(4,114)	(10,078)	
Accelerated vesting of options		3,897	
Cumulative effect of change in accounting principle	18,103		
Deferred tax provision	2,981	36,927	37,812
Dry hole costs	7,791	15,779	1,249
Impairments of leasehold costs	5,564	5,236	3,900
Changes in operating assets and liabilities, net of the effects from the purchase of Stellarton:			
Decrease (increase) in accounts receivable	15,966	43,520	(42,232)
(Increase) decrease in inventories	(114)	(109)	307
(Increase) decrease in other current assets	(1,762)	388	(1,541)
(Decrease)increase in accounts payable and accrued expenses	(5,820)	(28,597)	15,549
(Increase) decrease in other assets, net	(1,108)	(2,937)	919
Net cash provided by operating activities	121,562	207,900	132,958
CASH FLOWS FROM INVESTING ACTIVITIES:			
Proceeds from sales of assets	10,781	52,366	9,681
Capital expenditures	(146,681)	(244,663)	(140,719)
Acquisition of Stellarton stock		(74,500)	
Direct costs of Stellarton acquisition		(3,107)	
Changes in accounts payable and accrued expenses for capital expenditures	(1,271)	(7,082)	13,300
Net cash used in investing activities	(137,171)	(276,986)	(117,738)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings of long-term bank debt	36,183	109,812	20,000
Repayments of long-term bank debt	(24,369)	(54,000)	(47,000)
Preferred stock dividends			(875)
Proceeds from exercise of stock options	2,158	11,163	17,679
Net cash provided by (used in) financing activities	13,972	66,975	(10,196)

	Years Ended December 31,		
Effect of exchange rate changes on cash	(4)	(227)	
NET CHANGE IN CASH AND CASH EQUIVALENTS	(1,641)	(2,338)	5,024
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	15,196	17,534	12,510
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 13,555	$ 15,196	$ 17,534
Supplemental disclosures of cash flow information:			
Cash paid during the year for:			
Interest	$ 5,662	$ 7,219	$ 4,941
Income taxes	1,084	7,421	840
Refund received of income tax deposit	6,000		
Supplemental schedule of noncash investing and financing activities:			
Debt assumed in Stellarton Acquisition	$	$ 16,800	$

See accompanying notes to consolidated financial statements.

TOM BROWN, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the Years Ended December 31, 2002, 2001 and 2000

(1) Nature of Operations

Tom Brown, Inc. and its wholly-owned subsidiaries (the "Company") is an independent energy company engaged in the exploration for, and the acquisition, development, marketing, production and sale of, natural gas and crude oil. The Company's industry segments are (i) the exploration for, and the acquisition, development, production, and sale of, natural gas and crude oil, (ii) the marketing, gathering and processing of natural gas and (iii) drilling gas and oil wells. The Company's marketing activities are primarily conducted through Retex, Inc. ("Retex") and contract drilling is conducted through Sauer Drilling Company ("Sauer"). The Company's operations are conducted in the United States and Canada. The Company's United States operations are presently focused in the Wind River and Green River Basins of Wyoming, the Piceance Basin of Colorado, the Paradox Basin of eastern Utah and western Colorado, the Val Verde and Permian Basins of west Texas and southeastern New Mexico, and the east Texas Basin. The Company also, to a lesser extent, conducts exploration and development activities in other areas of the continental United States. The Company expanded its operations into Canada in 2001, establishing western Canada as a core area through the acquisition of Stellarton Energy Corporation ("Stellarton"). This transaction was completed in January 2001. The Canadian operations are focused in the Carrot Creek, Edson and Davey Lake areas of the western sedimentary basin of Alberta.

Wildhorse was originally formed by KN Energy, Inc. ("KNE") and the Company in January 1996. KNE was subsequently acquired by Kinder Morgan Inc. ("KM"). Initially, Wildhorse was owned fifty-five percent (55%) by KNE and forty-five percent (45%) by the Company. The Company dedicated a significant amount of its Rocky Mountain gas reserves to Wildhorse and KNE contributed substantial gas marketing contracts. The Company also transferred a natural gas storage facility in western Colorado to Wildhorse. The principal purpose of Wildhorse was to provide services related to natural gas, natural gas liquids and other natural gas products, including gathering, processing and storage services. In September 1999, Wildhorse assigned 100% of its marketing operations to Retex. Firm transportation contracts were also assigned 55% to KM and 45% to Retex at that time. In November 2000, the remaining gathering and processing assets were distributed to the Company in anticipation of the dissolution of Wildhorse. KM received the storage facility and a cash payment of $14.7 million. TBIFS was formed as a wholly-owned subsidiary of Tom Brown, Inc. to administer the gathering and processing assets received in the Wildhorse distribution. In 2001, TBIFS selectively sold many of the gathering and processing facilities received in the Wildhorse asset distribution, retaining only those gathering systems considered integral to the Company's operations. The Wind River gathering system was the main system retained. In 2002, the Company liquidated TBIFS to transfer the remaining gathering and processing assets to the parent company, Tom Brown, Inc.

Substantially all of the Company's production is sold under market-sensitive contracts. The Company's revenue, profitability and future rate of growth are substantially dependent upon the price of, and demand for, oil, natural gas and natural gas liquids. Prices for natural gas, crude oil and natural gas liquids are subject to wide fluctuation in response to relatively minor changes in their supply and demand as well as market uncertainty and a variety of additional factors that are beyond the control of the Company. These factors include the level of consumer product demand, weather conditions, domestic and foreign governmental regulations, the price and availability of alternative fuels, political conditions in foreign countries, the foreign supply of natural gas and oil and the price of foreign imports and overall economic conditions. The Company is affected more by fluctuations in natural gas prices than oil prices because a majority of its production (84 percent in 2002 and 2001 on a

volumetric equivalent basis) is natural gas.

(2) Summary of Significant Accounting Policies

Principles of Consolidation and Basis of Presentation

The accompanying consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries. The Company's proportionate share of revenues and expenses associated with certain interests in a gas and oil partnership were consolidated in the accompanying financial statements for the periods prior to Wildhorse asset distribution. All significant intercompany accounts and transactions have been eliminated. Certain reclassifications have been made to amounts reported in previous years to conform to the 2002 presentation.

Inventories

Inventories consist of pipe, other production equipment and natural gas placed in storage. Inventories are stated at the lower of cost (principally first-in, first-out) or estimated net realizable value.

Property and Equipment

The Company accounts for its natural gas and crude oil exploration and development activities under the successful efforts method of accounting. Under such method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Gas and oil lease acquisition costs are also capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for gas and oil leases, are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities. The sale of a partial interest in a proved property is accounted for as a cost recovery and no gain or loss is recognized as long as this treatment does not significantly affect the unit-of-production amortization rate. A gain or loss is recognized for all other sales of producing properties.

Maintenance and repairs are charged to expense; renewals and betterments are capitalized to the appropriate property and equipment accounts. Upon retirement or disposition of assets, the costs and related accumulated depreciation are removed from the accounts with the resulting gains or losses, if any, reflected in results of operations.

Unproved properties with significant acquisition costs are assessed quarterly on a property-by-property basis and any impairment in value is charged to expense. Unproved properties whose acquisition costs are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive, based on historical experience, is amortized over the average holding period. If the unproved properties are determined to be productive, the related costs are transferred to proved gas and oil properties. Proceeds from sales of partial interests in unproved leases are accounted for as a recovery of cost without recognizing any gain or loss.

The Company reviews its gas and oil properties for impairment whenever events and circumstances indicate a decline in the recoverability of their carrying value. The Company estimates the expected future cash flows of its gas and oil properties and compares such future cash flows to the carrying amount of the gas and oil properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will adjust the carrying amount of the oil and gas properties to fair value. The factors used to determine fair value include estimates of proved reserves, future commodity prices, future production estimates, anticipated capital expenditures, and a discount rate commensurate with the risk associated with realizing the expected cash flows projected. There were no impairments of producing gas and oil properties in 2002, 2001 or 2000.

The provision for depreciation, depletion and amortization of oil and gas properties is calculated on a basin-by-basin basis using the unit-of-production method. Included in such calculations are estimated future dismantlement, restoration and abandonment costs, net of estimated salvage values.

Other property and equipment is recorded at cost or estimated fair value upon acquisition and depreciated using the straight-line method over their estimated useful lives. Gas gathering, processing and other plant equipment is generally depreciated using the straight-line method over estimated useful lives that range from 10 to 20 years.

Natural Gas Revenues

The Company utilizes the accrual method of accounting for natural gas revenues whereby revenues are recognized as the Company's entitlement share of gas is produced based on its working interests in the properties. The Company records a receivable (payable) to the extent it receives less (more) than its proportionate share of gas revenues. At December 31, 2002 and 2001, the net imbalance positions were not significant.

Foreign Currency Translation

The functional currency of the Company's Canadian subsidiary is the Canadian dollar. For purposes of consolidation, substantially all assets and liabilities of the Canadian operations are translated into U.S. dollars at exchange rates in effect at the balance sheet dates. Unrealized currency translation adjustments are accumulated as a separate component of accumulated other comprehensive income within stockholders' equity. Income and expense items are translated at average exchange rates during the year. As a result of the change in the Canadian dollar relative to the U.S. dollar, the Company reported translation losses of $80,000 in 2002 and $790,000 in 2001.

Derivative Financial Instruments

In order to increase financial flexibility and to protect the Company against commodity price fluctuations, the Company may, from time to time in the ordinary course of business, enter into non-speculative hedge transactions, including, commodity swap agreements, forward sale contracts, commodity futures, options and other similar agreements relating to natural gas and crude oil expected to be produced.

In June 1998, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS 133 establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its fair value. It also requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement, and requires that a company formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. SFAS 133 is effective for all fiscal quarters of fiscal years beginning after June 15, 2000. In June 2000, the FASB issued SFAS 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities". This pronouncement amended portions of SFAS 133 and was adopted by the Company with SFAS 133 effective January 1, 2001.

SFAS 133, in part, allows special hedge accounting for cash flow hedges and provides that the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of Other Comprehensive Income and be reclassified into earnings in the same period or periods during which the hedged forecasted transaction affects earnings.

Recently Issued Accounting Standards

In June 2001, the FASB issued SFAS No. 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 is reviewed at least annually for impairment. The Company adopted SFAS No. 142 on January 1, 2002, designating its reporting units as (i) gas and oil exploration and development in the United States, (ii) gas and oil exploration and development in Canada, (iii) marketing, gathering and processing and (iv) drilling. The first two reporting units are included in the gas and oil exploration and development segment. A fair value based test was conducted effective January 1, 2002 to evaluate the goodwill originally recorded in conjunction with the January 2001 Stellarton Energy Corporation acquisition. The fair value of the reporting unit was determined with reference to the estimated discounted future net revenues of the underlying gas and oil reserves as of the date of the test and other financial considerations, including going-concern value. This test resulted in the Company recording a non-cash charge of $18.1 million in the quarter ended March 31, 2002. This expense has been reflected in the consolidated statements of operations as a cumulative effect of a change in accounting principle. After this write down, the Company has no goodwill recorded on its consolidated balance sheet or associated amortization expense recorded on its consolidated statements of operations. To the extent that goodwill is recognized in conjunction with future transactions, the Company would expect to perform its annual impairment test on December 31. Had SFAS No. 142 been effective for the years ended December 31, 2001 and 2000, the Company's net income would have been as follows (in thousands, except per share amounts):

	Years Ended December 31,	
	2001	2000
Net (loss) income		
As reported	$ 69,503	$ 65,703
Amortization of goodwill (net of tax effect)	563	
Pro forma	$ 70,066	$ 65,703
Basic net (loss) income per common share:		
As reported	$ 1.78	$ 1.79
Pro forma	$ 1.80	$ 1.79

	Years Ended December 31,	
Diluted net (loss) income per common share:		
As reported	$ 1.73	$ 1.76
Pro forma	$ 1.74	$ 1.76

In connection with a review of the Company's financial statements by the staff of the Securities and Exchange Commission, the Company has been made aware that an issue has arisen within the industry regarding the application of provisions of SFAS No. 142 and SFAS No. 141, "Business Combinations," to companies in the extractive industries, including gas and oil companies. The issue is whether SFAS No. 142 requires registrants to reclassify costs associated with mineral rights, including both proved and unproved leasehold acquisition costs, as intangible assets in the balance sheet, apart from other capitalized gas and oil property costs. Historically, the Company and other gas and oil companies have included the cost of these gas and oil leasehold interests as part of gas and oil properties. Also under consideration is whether SFAS No. 142 requires registrants to provide the additional disclosures prescribed by SFAS No. 142 for intangible assets for costs associated with mineral rights.

If it is ultimately determined that SFAS No. 142 requires the Company to reclassify costs associated with mineral rights from property and equipment to intangible assets, the amounts that would be reclassified are as follows:

	December 31,	
	2002	2001
	(In thousands)	
INTANGIBLE ASSETS:		
Proved leasehold acquisition costs	$ 340,058	$ 315,530
Unproved leasehold acquisition costs	62,645	76,384
Total leasehold acquisition costs	402,703	391,914
Less: Accumulated depletion	107,158	84,076
Net leasehold acquisition costs	$ 295,545	$ 307,838

The reclassification of these amounts would not effect the method in which such costs are amortized or the manner in which the Company assesses impairment of capitalized costs. As a result, net income would not be affected by the reclassification.

In July 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted each period toward its future value, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity reports a gain or loss upon settlement to the extent the actual costs differ from the recorded liability. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. The Company will adopt