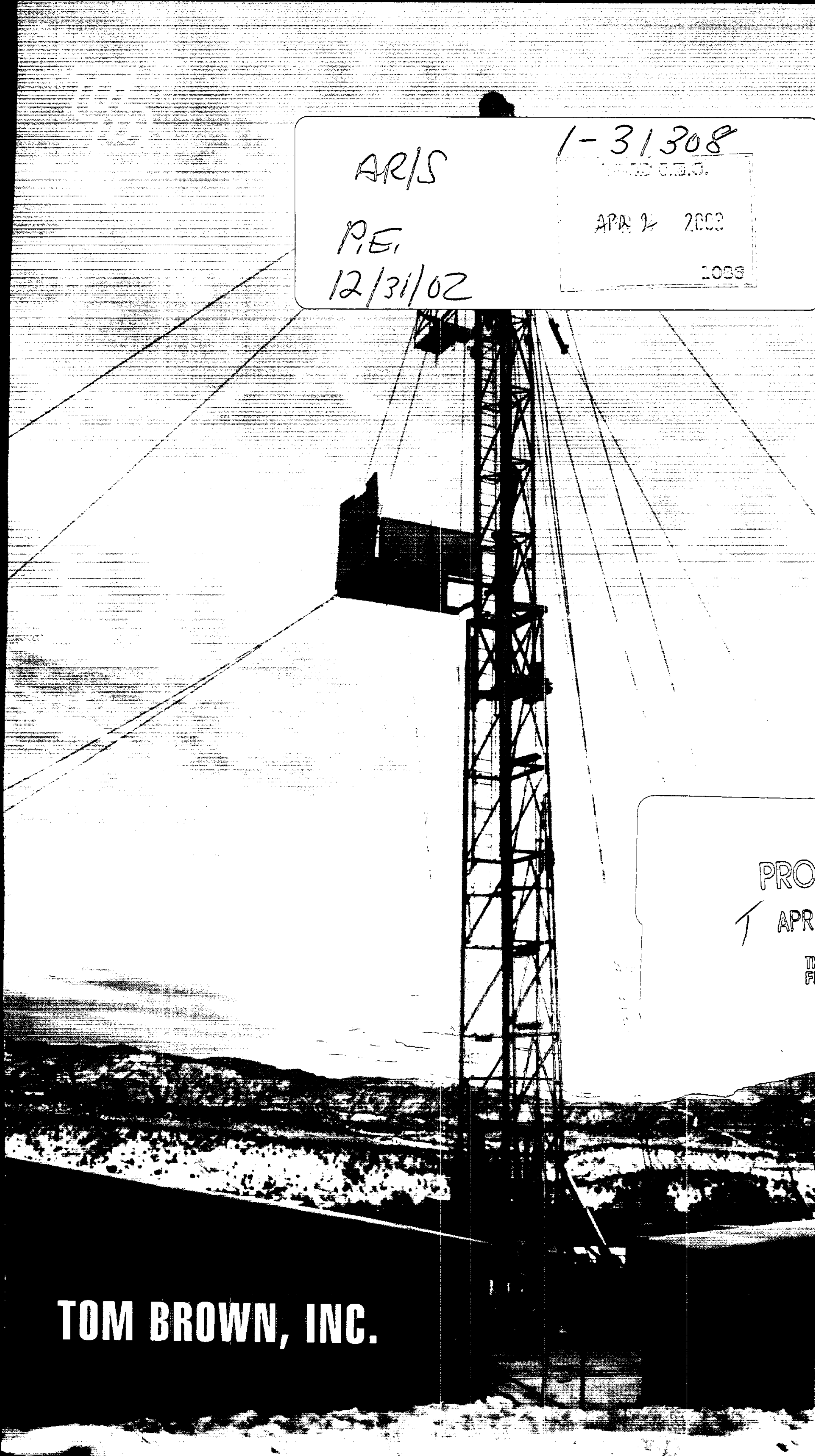


TOM BROWN, INC.

ANNUAL REPORT 2002

Corporate Profile

Tom Brown, Inc. is a Denver, Colorado based independent energy company engaged in the exploration for, and the development, acquisition, production and marketing of natural gas, natural gas liquids and crude oil primarily in the gas-prone basins of the North American Rocky Mountains and Texas. The Company maintains a dominant land position in its core operating areas, with over 2.1 million net acres, 87% of which are undeveloped.

At year-end 2002, the Company's proved reserves totaled 750 billion cubic feet equivalent (Bcfe). The year-end 2002 proved reserves are 90% natural gas and 85% of the reserves are from fields located in the U.S. and Canadian Rockies. Net daily production in 2002 averaged 234 million cubic feet equivalent (Mmcfepd) a 12% increase over 2001. Tom Brown has achieved compound annual growth in production of 20% over the last three years.

Tom Brown, Inc. (Tom Brown or TBI) trades on the New York Stock Exchange under the symbol TBI.

Contents

Why the Rockies?

Tom Brown's commitment to the Rockies dates back to the mid-1970s. A vision that the Rockies would be a significant source of natural gas supply for the country lead the Company to increase its asset base in the region. Today, Tom Brown has one of the largest acreage positions in the Rockies and is a significant producer of natural gas in the region. The vision has come to fruition in that the Rockies has become a major source of natural gas production for the country (see page 6, "Why the Rockies" for further discussion).

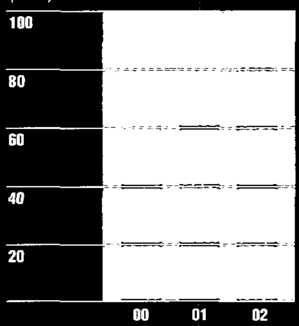
In 2002 Rockies natural gas price traded at a steep discount to Henry Hub, Louisiana (the settlement point for the NYMEX). Prices in the northern Rockies ("Colorado and Wyoming") traded as low as $0.60 per million British thermal units (MMBtu) late in the third quarter of 2002. Rockies producers are partly a victim of their own success. This dramatic disconnect between the Rockies gas price and the rest of the country is partly explained by increasing production volumes coming from the region.

The widening and tightening of the Rockies basis differential can be seen over the years. However, what has remained consistent is the important role the Rockies continues to play in providing an increasing supply of domestic clean-burning natural gas to the country. Tom Brown has long recognized this potential and will continue to expand its position as one of the premier Rockies producers.

Cover: Sunrise at Tom Brown's White River Dome field near Meeker, Colorado.


WESTERN CANADIAN SEDIMENTARY BASIN
Calgary
BIG HORN BASIN
WIND RIVER BASIN
Casper
GREATER GREEN RIVER BASIN
PICEANCE BASIN
Denver
PARADOX BASIN
PERMIAN BASIN
Midland
EAST TEXAS BASIN

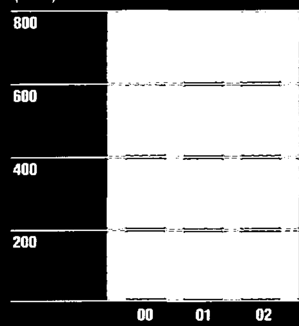
PRODUCTION
(Bcfe)



Natural Gas

Natural gas liquids and oil

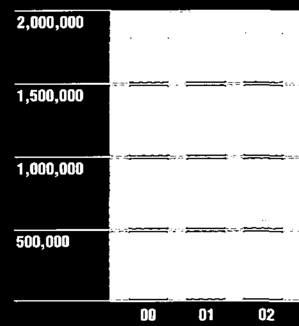
PROVED RESERVES
(Bcfe)



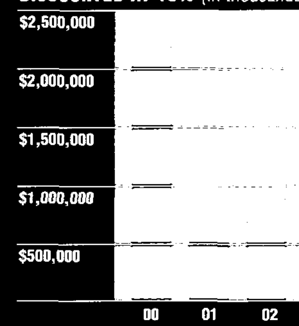
Natural Gas

Natural gas liquids and oil

NET UNDEVELOPED ACRES

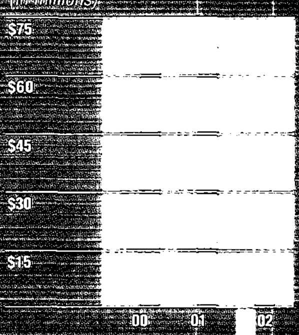


SEC NET PRESENT VALUE DISCOUNTED AT 10% *(in thousands)*



Average wellhead natural gas price used in determining the present value:
2000-$8.82 2001-$2.20 2002-$3.33

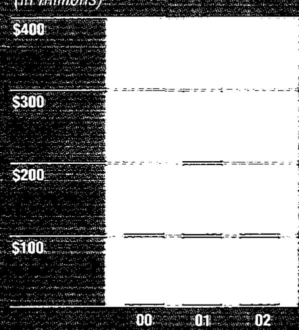
EARNINGS (LOSS)
(in millions)



Net Income (loss)

Net Income before cumulative effect of change in accounting principles

CAPITAL EXPENDITURES
(in millions)

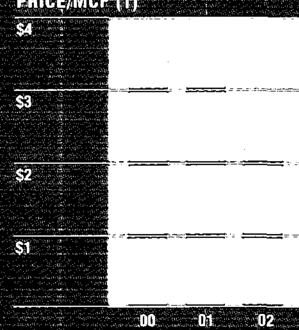


Acquisitions

Exploration

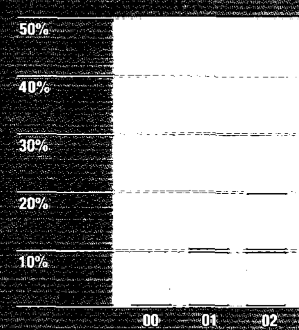
Development

REALIZED NATURAL GAS PRICE/MCF (1)



(1) Includes the effect of hedging

NET DEBT/TOTAL CAPITALIZATION



OPERATIONS

(In thousands, except per unit amounts)	*2000*	*2001*	*2002*
Year-end Reserves:			
Natural gas *(Mmcf)*	535,373	641,579	674,037
Oil and natural gas liquids *(MBbl)*	11,193	15,007	12,680
Total equivalent *(Mmcfe)*	602,531	731,621	750,116
SEC PV-10, discounted at 10%, pre-tax	$ 2,187,925	$ 501,288	$ 883,353
Production:			
Natural gas *(Mmcf)*	51,199	63,824	72,167
Natural gas liquids *(MBbl)*	1,074	1,217	1,382
Oil *(MBbl)*	773	881	843
Total equivalent *(Mmcfe)*	62,282	76,412	85,517
Average Sales Price:			
Natural gas *($/Mcf)*	$ 3.46	$ 3.71	$ 2.19
Natural gas liquids *($/Bbl)*	16.77	14.07	12.05
Oil *($/Bbl)*	28.05	23.09	23.41
Total equivalent *($/Mcfe)*	3.48	3.59	2.27
Undeveloped acreage:			
Gross	2,666	2,892	2,710
Net	1,821	1,942	1,852

FINANCIAL

(In thousands, except per share amounts)	*2000*	*2001*	*2002*
Total revenues	$ 253,910	$ 326,324	$ 235,645
Income before cumulative effect of change in accounting principles	65,703	67,477	9,926
Net (loss) income applicable to common stock	65,703	69,503	(8,177)
Per share, diluted	1.76	1.73	(0.20)
Weighted average common shares outstanding, diluted	37,897	40,227	40,327
Total exploration and production capital expenditures	$ 126,710	$ 340,454	$ 154,497
Total assets	$ 629,535	$ 844,975	$ 850,952
Working capital	$ 38,139	$ 11,278	$ (8,887)
Property and equipment, net	$ 509,762	$ 738,526	$ 776,485
Long-term debt	$ 54,000	$ 120,570	$ 133,172
Stockholders' equity	$ 488,893	$ 575,228	$ 563,618

Letter To Shareholders

Tom Brown's employees posted another year of solid performance, growing production volumes by 12% and lowering operating costs by 10% on a per unit basis while replacing 137% of our production at a finding and development cost of $1.32/Mcfe. These operational results were somewhat offset by historically wide price differentials for Rockies gas. Low Rockies prices throughout much of the year caused us to temporarily curtail production of approximately 20 MMcfd and to significantly slow down our Rockies drilling activity. It is in the best interest of shareholders and royalty owners not to sell gas for unrealistically low prices. TBI and other Rockies producers are victims of our own success. Gas production from the Rockies has grown so fast that there is not enough pipeline capacity to move the increasing volumes to major consuming markets in other parts of the country. Transportation shortages cause gas prices to drop and, as a result, new major pipeline expansions are announced, albeit with multi-year permitting and construction timeframes. These supply/transportation cycles have been experienced before and they will probably happen again.

The Rocky Mountain area possesses the single largest onshore resource of natural gas in the U.S. and most of this resource base has yet to be exploited. TBI is one of the premier Rockies natural gas producers and we have been diligently strengthening our positions in the Green River, Paradox, Piceance and Wind River basins. We continue to maximize our dominant acreage holdings and have active exploration and development drilling programs in each basin. Tom Brown's long term commitment to the Rockies remains both visionary and timely. We are confident that this region will continue to be crucial to our country's domestic natural gas supply and that the price damaging pipeline constraints will be solved.

Last year's Rockies price differential blowout highlights the need for diversification and TBI will continue to benefit from our concentrated push into western Canada and east and west Texas over the last several years. These areas provide TBI with exposure to higher gas prices, better reservoirs and more reasonable land access. Operating on the federal lands that comprise much of the Rockies has definitely become more challenging primarily due to several litigious anti-development groups bent on shutting down reasonable, regulated access to America's domestic, clean-burning natural gas resources. The state, provincial and private lands that make up much of our new core areas provide more logical and efficient permitting procedures that allow reasonable and responsible access. Such access is healthy for our nation and our company.

We have assembled teams of highly experienced management, operational and technical personnel with local expertise in each of our core areas. They are consistently adding to our portfolio of exploration and development drilling opportunities and continue to improve our ability to create value. Last year our teams in the U.S. Rockies grew production by 14%. Tom Brown Resources Ltd., our wholly owned subsidiary in Canada, grew production by 5%. They have built a strong team over the last 18 months which has generated new projects with exciting growth potential. We are doubling our capital commitment in Canada for 2003 which will allow them to ramp up activity and accelerate their growth. Our Southern Region grew production by 10% in 2003. In west Texas at our Deep Valley horizontal Devonian play, the Trees Estate discovery well is on track to make 8 to 12 Bcfg and we are very encouraged by our initial completion attempts at the Beefmaster wildcat. If successful, this six mile step-out confirmation well and the Trees Estate discovery set up a very significant area in which to begin development of this potentially large resource.

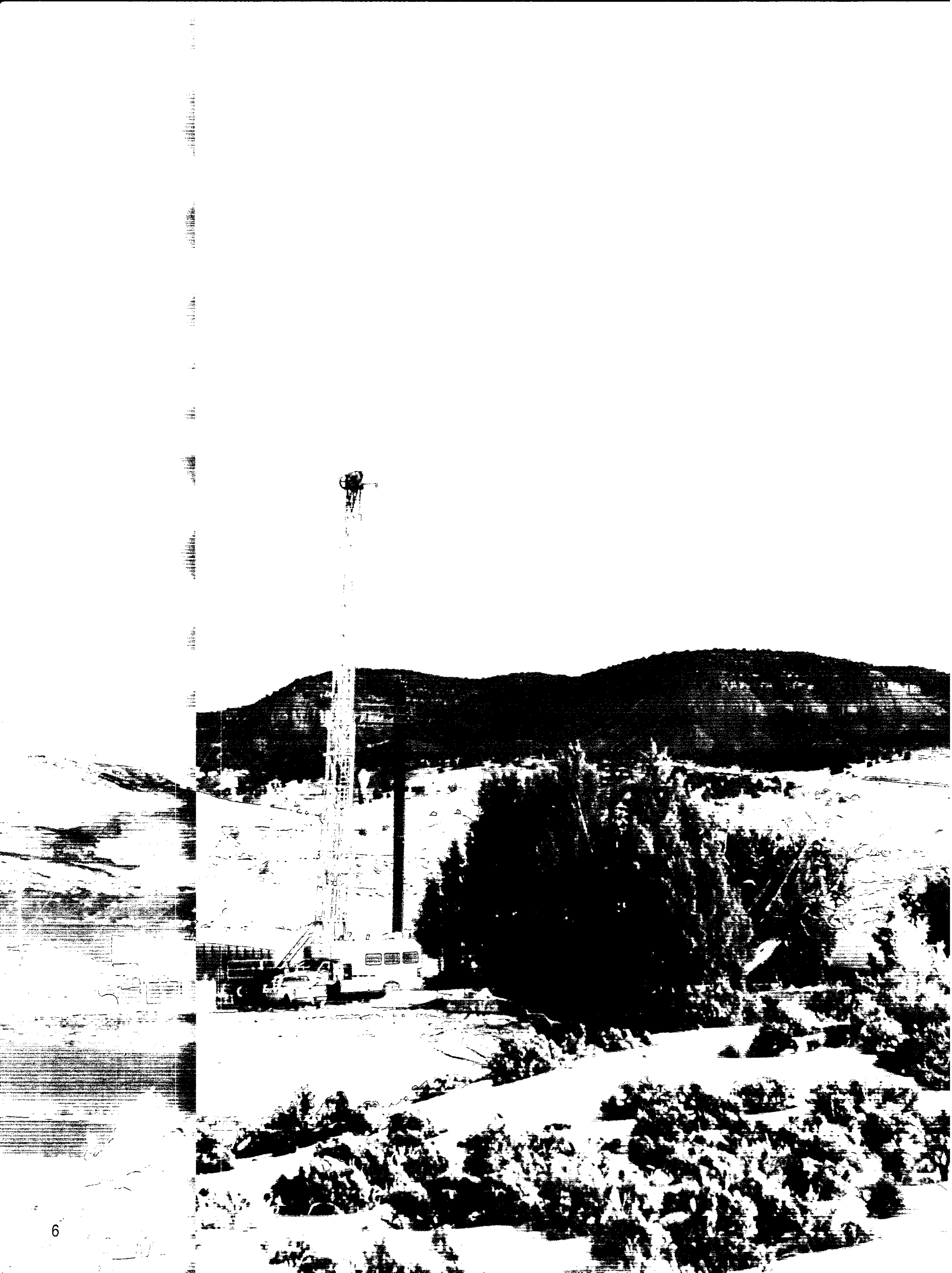
We are a very efficient and focused exploitation company utilizing some of the latest reservoir characterization technologies available, especially with regard to unconventional reservoirs. New exploitation opportunities are replenished from acquisition and exploration success. TBI has one of the strongest balance sheets in the industry with a net debt to total capitalization ratio of 20%. This conservative approach to leverage gives TBI considerable flexibility to capture acquisition opportunities in the future. We are also a focused "prospect generating" exploration company. TBI's consistent commitment to exploration is beginning to pay dividends and our diverse exploration portfolio will provide exciting new discovery potential for shareholders over the next several years.

While not widely recognized, our nation is entering into a period of tighter energy supply. The country's natural gas production base of 48 to 50 billion cubic feet per day (Bcfpd) is on an annual decline of 29%. As a nation we need to add new production of approximately 14 Bcfd every year just to keep our production flat. Domestic clean-burning natural gas has many advantages over coal and foreign oil and many believe that it is the nation's fuel of choice for the foreseeable future. However, supply must remain reliable and reasonably priced for the well-being of our economy and our nation. As I write this letter gas prices have once again soared to new highs. Diminished North American drilling activity caused by low gas prices during much of 2002 will result in production declines and higher gas prices until the industry increases drilling activity to sustainable high levels. In order to achieve that goal, major areas of potential that are currently off limits or severely restricted will need to be re-evaluated with regard to their prospectivity and actual, rather than emotional, environmental impact.

TBI will continue to strive for improvement in every aspect of our business. We remain dedicated to creating long-term shareholder value by providing exposure to significant upside growth due to our unique acreage position, our diverse exploration and development drilling portfolio and our positioning as one of the premier North American mid-cap natural gas companies. At a time when the nation is in need of domestic clean burning energy, we are proud to be providing more of what our country needs. On behalf of our Board of Directors and employees, I thank our shareholders for their continued trust and support.

JAMES D. LIGHTNER

Chairman, Chief Executive Officer and President



Why the Rockies?

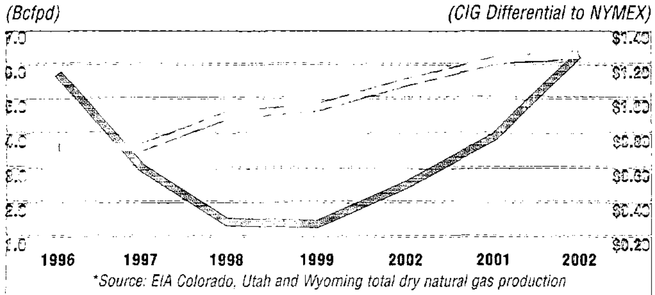
Tom Brown's focus on the Rockies dates back to the mid-1970s with the discovery of the Muddy Ridge field in the Wind River basin of Wyoming. The Company recognized the large resource potential and the importance the region would play in meeting the country's growing demand for natural gas. Over the years, the Company has continued to expand its position in the gas prone Rocky Mountain basins. Tom Brown's U.S. Rocky Mountain properties account for 74% of its total reserves. Despite the price difficulties experienced in 2002, Tom Brown is committed to the long term fundamentals and potential within the Rockies.

Rockies Production Growth

According to the Energy Information Administration (EIA), the Northern Rockies ("Colorado, Wyoming and Utah") has increased natural gas supply since 1996 at an annual compounded growth rate of 10%, increasing from 3.6 billion cubic feet per day (Bcfpd) to an estimated 6.3 Bcfpd in 2002. The 2.7 Bcfpd increase in natural gas supply primarily came from Wyoming with major increases in production from the coal bed methane (CBM) play in the Powder River basin, Jonah field in the Greater Green River basin, and from the Madden and Pavillion fields of the Wind River basin.

Demand for natural gas in the Northern Rockies has not changed significantly, growing from 1.6 Bcfpd in 1996 to around 1.8 Bcfpd in 2001 or at a compounded annual growth rate of just 2%. Since 1996, supply growth has outpaced local demand by a net 2.5 Bcfpd, all of which needs to be exported out of the region.

NATURAL GAS PRODUCTION* VS. CIG DIFFERENTIAL



*Source: EIA Colorado, Utah and Wyoming total dry natural gas production

Rockies Reserve Growth

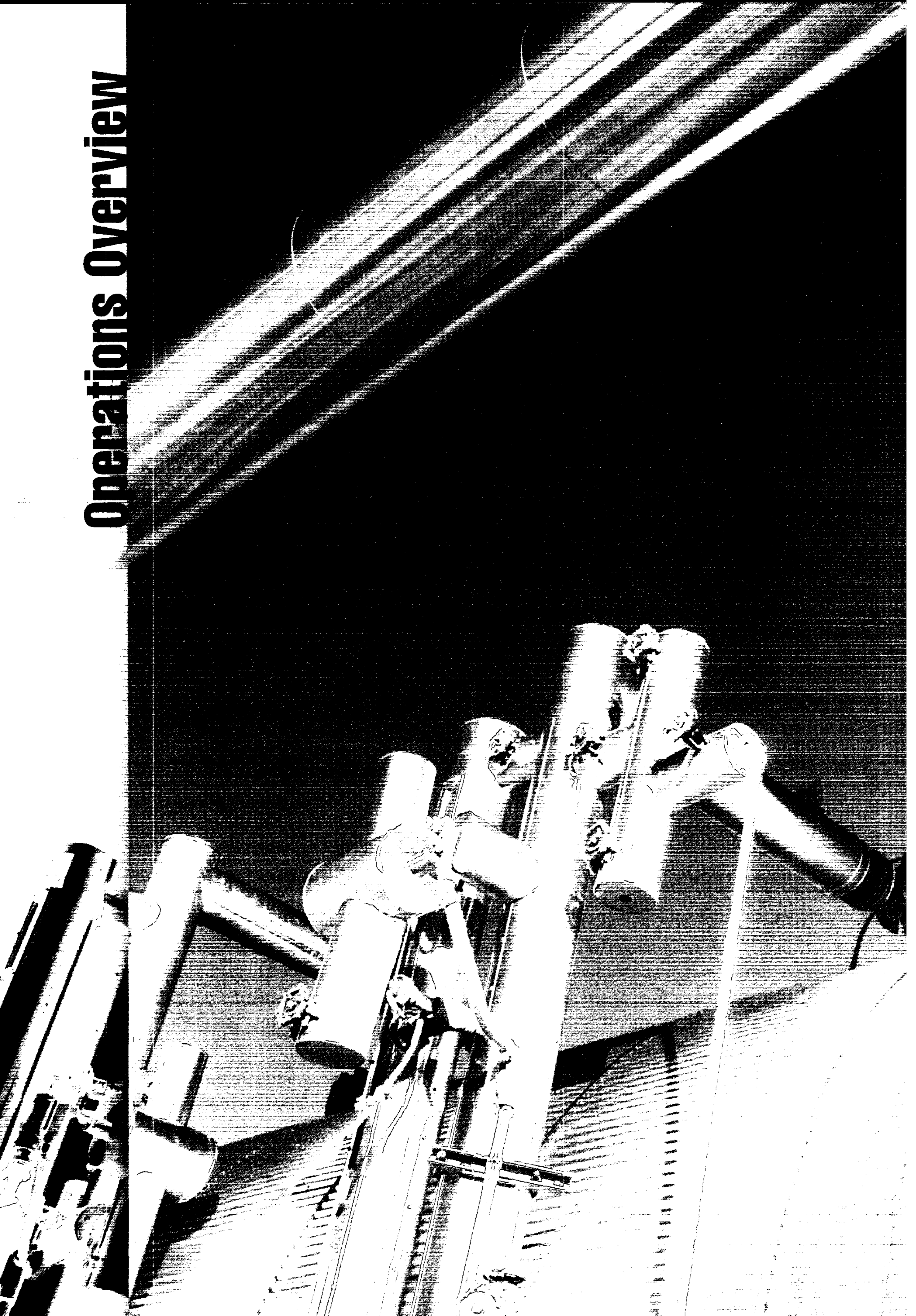
In the late 1970s the U.S. Rockies represented just a fraction of our country's natural gas reserves. According to the EIA, in 1977 the Northern Rockies made up around 6% of the total U.S. lower-48 reserves. This figure had grown to nearly 32% by year-end 2001. The most significant increase in the reserves happened over the last ten years doubling since 1991 to 36 Tcf by year-end 2001. In 2001, total U.S. lower-48 reserves totaled 175 Tcf, a 6.5 Tcf increase over 2000. The Northern Rockies represented over 70% of this increase. Additionally, the U.S. Geological Survey (USGS) in its November 2002 update to the National Oil and Gas Assesment, estimates that the Rockies contain over 170 Tcf of undiscovered natural gas potential using today's drilling and completion technology. The Rockies will continue to be a major source of clean-burning domestic energy and represents the single largest untapped onshore natural gas region in the U.S.

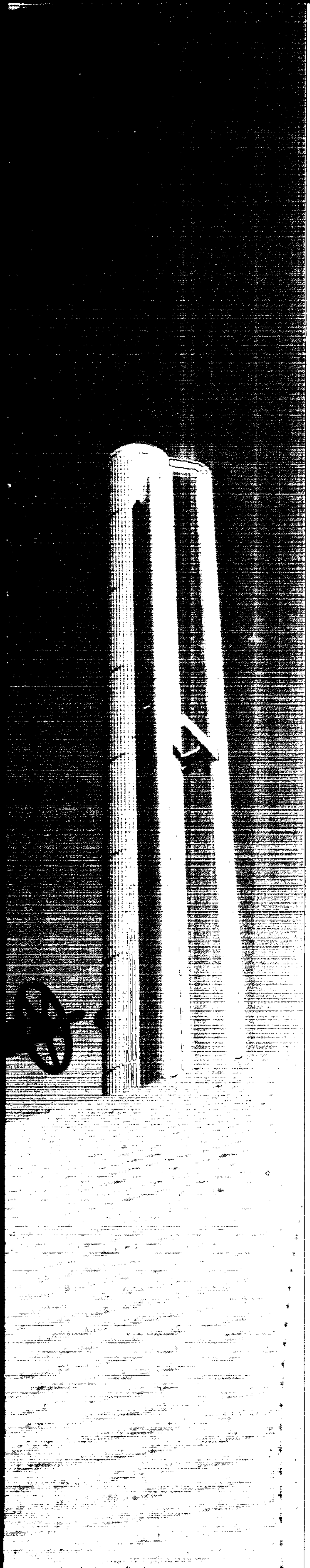
Northern Rocky Mountain Natural Gas Prices

The Rockies natural gas producers are a victim of their own success. Rising production and the lack of significant new pipelines out of the region has caused gas price realizations to be depressed relative to the rest of the country.

Looking forward the earliest catalyst to improve differentials is the doubling of the Kern River pipeline capacity to approximately 1.7 Bcfpd. This expansion is expected to be completed by May 2003 and will transport gas from western Wyoming to markets in Utah, Nevada and California. This expansion represents a significant increase in take-away capacity out of the Rockies. The next inline is El Paso Corporation's fully subscribed Cheyenne Plains Pipeline. This new pipeline, projected to be in service in mid-2005, will be able to deliver 540 Mmcfpd of natural gas from the Cheyenne hub in Wyoming to Kansas.

Operations Overview



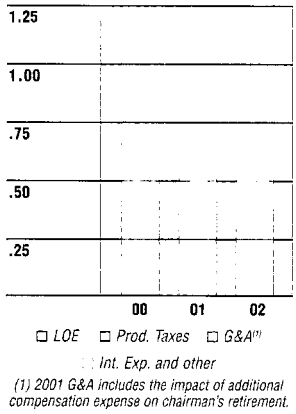


Tom Brown had a strong year operationally in 2002. The Company's oil and gas production grew 12% in 2002 over 2001, hitting an all time high of 245 Mmcfepd in the second quarter of 2002. Additionally, as a result of continually focusing on cost containment, oil and gas lease operating expense was reduced by 10% on a per unit basis in 2002 as compared to 2001. As a result of the extremely low Rockies' natural gas prices, Tom Brown shut-in approximately 20 MMcfpd late in the third quarter through early in the fourth quarter when the Colorado Interstate Gas (CIG) gas price was trading at or below one dollar per MMBtu. Rockies natural gas prices recovered considerably in November and December 2002 climbing back to around $3/MMbtu with the onset of some early cold winter weather that stimulated local heating demand in the Denver market.

Adjusting to the weak natural gas prices in the Rockies, the Company also significantly reduced its drilling activity and capital expenditures in the second half of 2002. Exploration and development capital expenditures (excluding acquisitions) for the year decreased by over 42%.

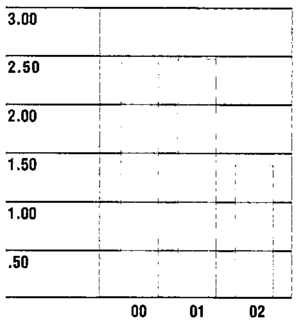
Tom Brown organizes it operations by teams responsible for geographic areas. These include the Wind River, the Greater Green River, the Piceance, the Paradox, Canada (the Western Canadian Sedimentary basin) and the Southern region (includes the Permian and East Texas basins).

OPERATING EXPENSES
($/Mcfe)



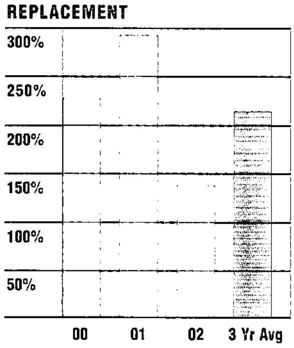
(1) 2001 G&A includes the impact of additional compensation expense on chairman's retirement.

NET CASH MARGIN*
($/Mcfe)

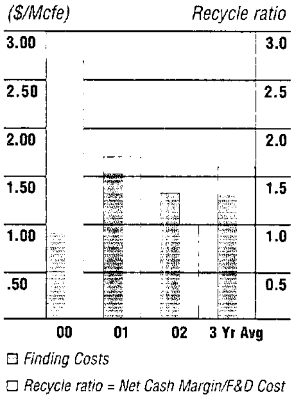


**Oil & Gas sales after hedge impact less direct cost: lease operating expense, production taxes, general and adminstrative expense, and interest expense and other*

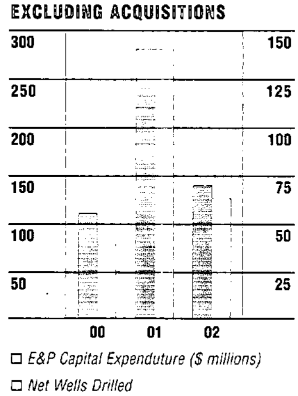
ALL-SOURCES RESERVE REPLACEMENT



ALL-SOURCES FINDING & DEVELOPMENT COST (F&D)
($/Mcfe) *Recycle ratio*



EXPLORATION & PRODUCTION CAPITAL EXENDITURES EXCLUDING ACQUISITIONS



TBI's Piceance basin team on location at the White River Dome field. Pictured from left to right: Byron Gale – Sr. Engineer, Blake Roush – Sr. Operations Foreman, Jerry Holder – Operations/Completion Superintendent, Doug Walton – Petroleum Engineer, Bob Mustard – Development Manager, Dayne Doucet – Petroleum Engineer, Dave Davenport – Landman

The Rockies

Wind River Basin

The Wind River basin is located in central Wyoming with boundaries including the Owl Creek Mountains to the north, Wind River Mountains to the west, Casper Arch to the east, and the Sweetwater Uplift to the south. The Wind River basin is about 200 miles long and 100 miles wide, encompassing an area of about 11,700 sq miles.

	2002	2001	2000
Production *(Mmcfepd)*	59.8	49.2	42.3
Total Gross Acreage *(in thousands)*	429	582	970
Total Net Acreage *(in thousands)*	344	412	761
E&P Capital Spending *(in millions)*	$26.3	$61.2	$42.9
Lease Operating Expense *(per Mcfe)*	$0.16	$0.17	$0.19

TBI's Wind River basin (WRB) team represents 25% of the Company's year-end 2002 proved reserves and 26% of its 2002 production. TBI's WRB operations are primarily conducted in the Pavillion, Muddy Ridge, and Frenchie Draw fields. The Pavillion and Muddy Ridge fields are located on the Northern Arapaho and Eastern Shoshone Wind River Indian Reservation.

In 2002, the Company drilled and completed 16 wells in the Wind River basin, and at year end one well was in the process of drilling. The majority of the drilling activity was in the Pavillion field (TBI 92% working interest) where 12 successful wells were drilled. The remainder of the drilling was in the Muddy Ridge field where Tom Brown drilled four wells. The Company produced an average of 59.8 Mmcfepd net in 2002 from the Wind River basin, an increase of 21% over the prior year.

Greater Green River Basin

The Greater Green River basin (GGRB) encompasses about 40,500 square miles and is a composite of several basins and adjacent uplifts in Wyoming and Colorado. The GGRB team accounts for 15% of TBI's year-end 2002 proved reserves and 9% of the 2002 production. The Company drilled or participated in five wells in the GGRB of which three were successful. In 2002, the Company also closed several niche property acquisitions in the GGRB adding 12.7 Bcfe of proved reserves for $14.9 million. These properties have a good mix of development and exploitation opportunities.

	2002	2001	2000
Production *(Mmcfepd)*	22.0	25.2	24.0
Total Gross Acreage *(in thousands)*	466	394	441
Total Net Acreage *(in thousands)*	272	248	292
E&P Capital Spending *(in millions)*	$8.2	$15.0	$16.8
Lease Operating Expense *(per Mcfe)*	$0.49	$0.39	$0.35

The Company controls over 270,000 net undeveloped acres in the GGRB, and continues to explore for large unconventional basin-centered and coal bed methane gas accumulations.

Piceance Basin

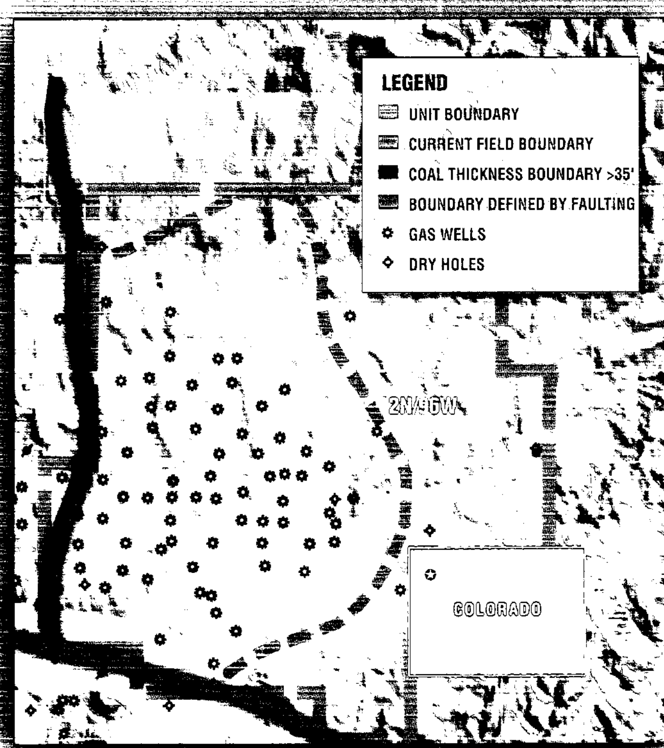
The Piceance basin of Colorado is about 100 miles long and 40-50 miles wide bounded on the northeast by the Axial Uplift, and on the east by the White River Uplift. The Piceance basin team accounts for 19% of TBI's year-end 2002 proved reserves and 14% of the 2002 production.

	2002	2001	2000
Production *(Mmcfepd)*	32.9	23.8	19.4
Total Gross Acreage *(in thousands)*	398	364	457
Total Net Acreage *(in thousands)*	335	300	337
E&P Capital Spending *(in millions)*	$26.0	$43.7	$14.0
Lease Operating Expense *(per Mcfe)*	$0.36	$0.39	$0.42

The Company drilled 26 wells in the Piceance basin during 2002. At year end, 23 of these wells had been completed, two were in the process of being completed and one well was abandoned. The majority of the drilling occurred in the Company's White River Dome (WRD) field (TBI 100% working interest) where 14 wells were drilled. The Company produced an average of 32.9 Mmcfepd net in 2002 from the Piceance basin, an increase of 38% over 2001.

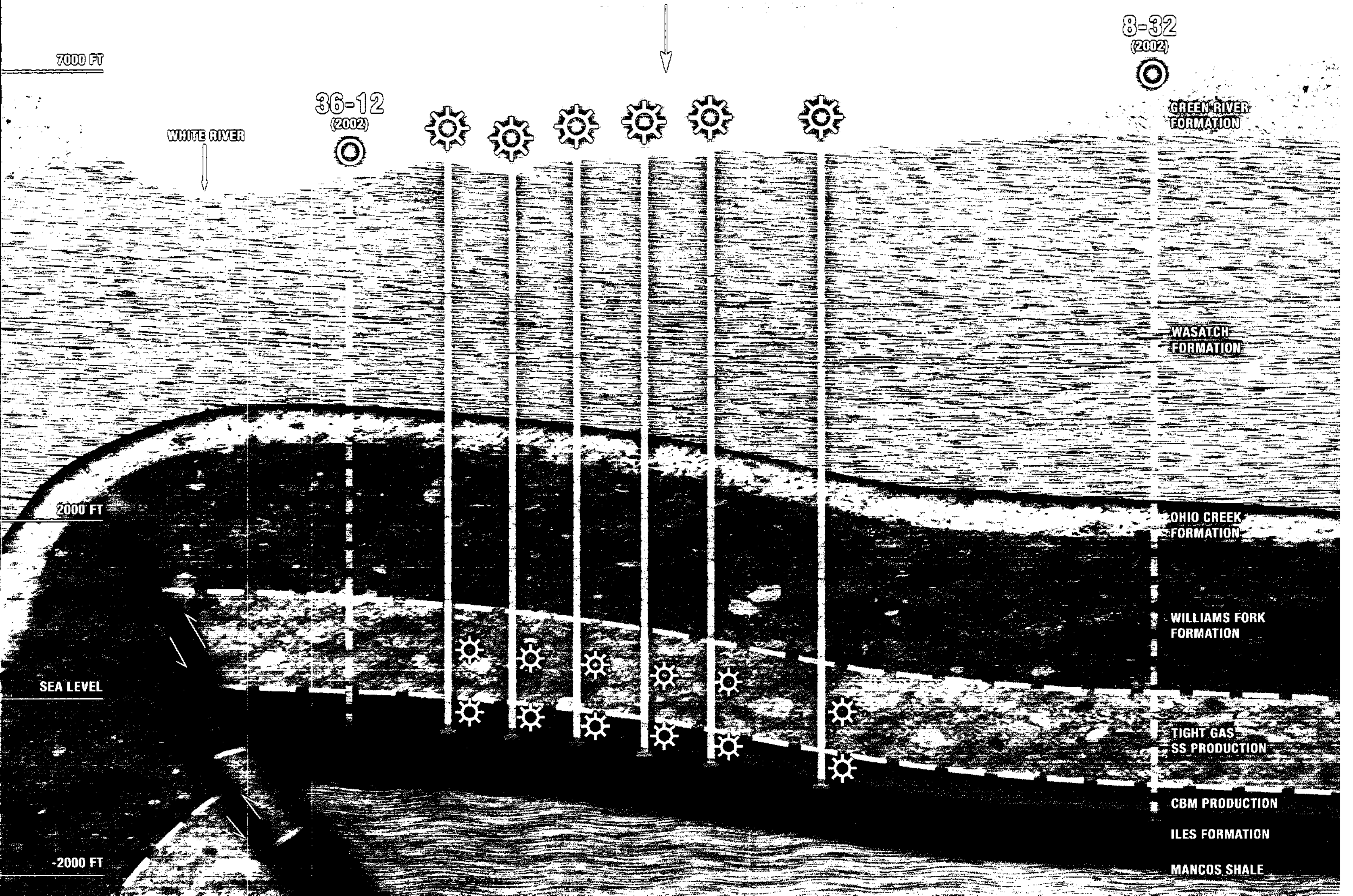
TBI's WRD field is a coal bed methane project producing from depths greater than 7,000 feet (see cross section). The Company has drilled fifty wells in the field since beginning the program in 2000. The Company is performing an extensive reservoir engineering study to evaluate the extent of this field's potential. Based upon the knowledge gained from WRD, Tom Brown is evaluating other coal bed methane projects within the Piceance.

Piceance Basin



WHITE RIVER DOME FIELD

WHITE RIVER DOME CROSS SECTION



Paradox Basin

The Paradox basin is in southeastern Utah and southwestern Colorado measuring approximately 280 miles long and 200 miles wide covering an area of about 33,000 square miles. The Paradox basin team made up 15% and 19% of Tom Brown's year-end 2002 proved reserves and 2002 production, respectively.

TBI has a dominant position in the Paradox basin controlling 341,000 net acres and a modern cryogenic gas processing plant. The Lisbon plant is the only facility in the Paradox basin equipped to handle all gas stream contaminants, which gives Tom Brown significant leverage to participate in other opportunities in the basin.

TBI grew its Paradox basin production 13% in 2002 as a result of the success at Andy's Mesa where the Company drilled four out of five successful wells.

	2002	2001	2000
Production *(Mmcfepd)*	44.7	39.7	34.3
Total Gross Acreage *(in thousands)*	362	345	236
Total Net Acreage *(in thousands)*	341	322	221
E&P Capital Spending *(in millions)*	$14.4	$20.9	$11.5
Lease Operating Expense *(per Mcfe)*	$0.62	$0.64	$0.68

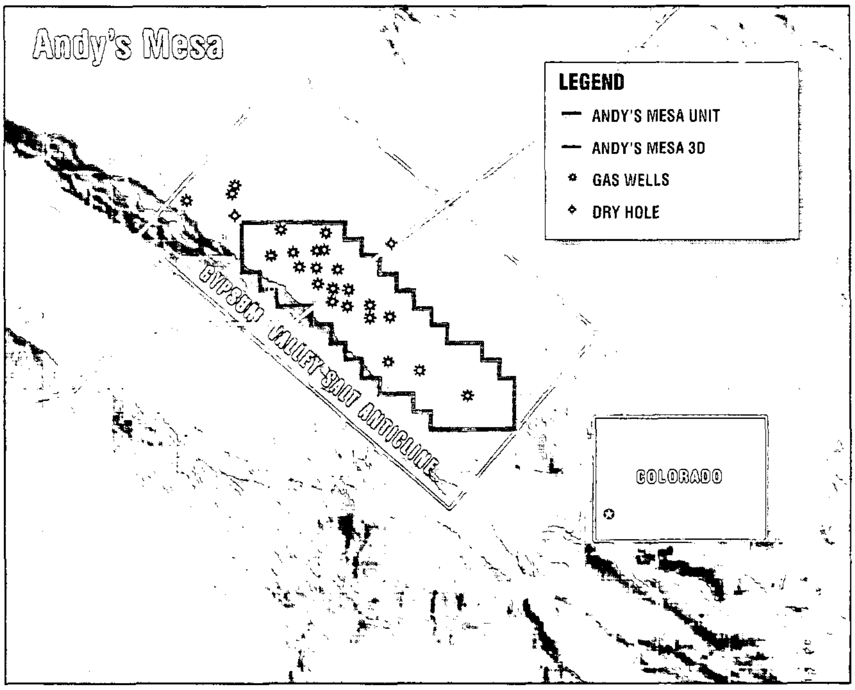
Andy's Mesa field is characterized by natural gas trapped in pinchouts of sandstone reservoirs along the steeply dipping flanks of northwest trending salt anticlines. The salt anticlines cover a significant area in the Paradox basin, and little exploration for this play type has occurred. TBI is well positioned to explore for new fields in this play due to its large acreage position in the basin and its knowledge and excellent results at Andy's Mesa.

Canada

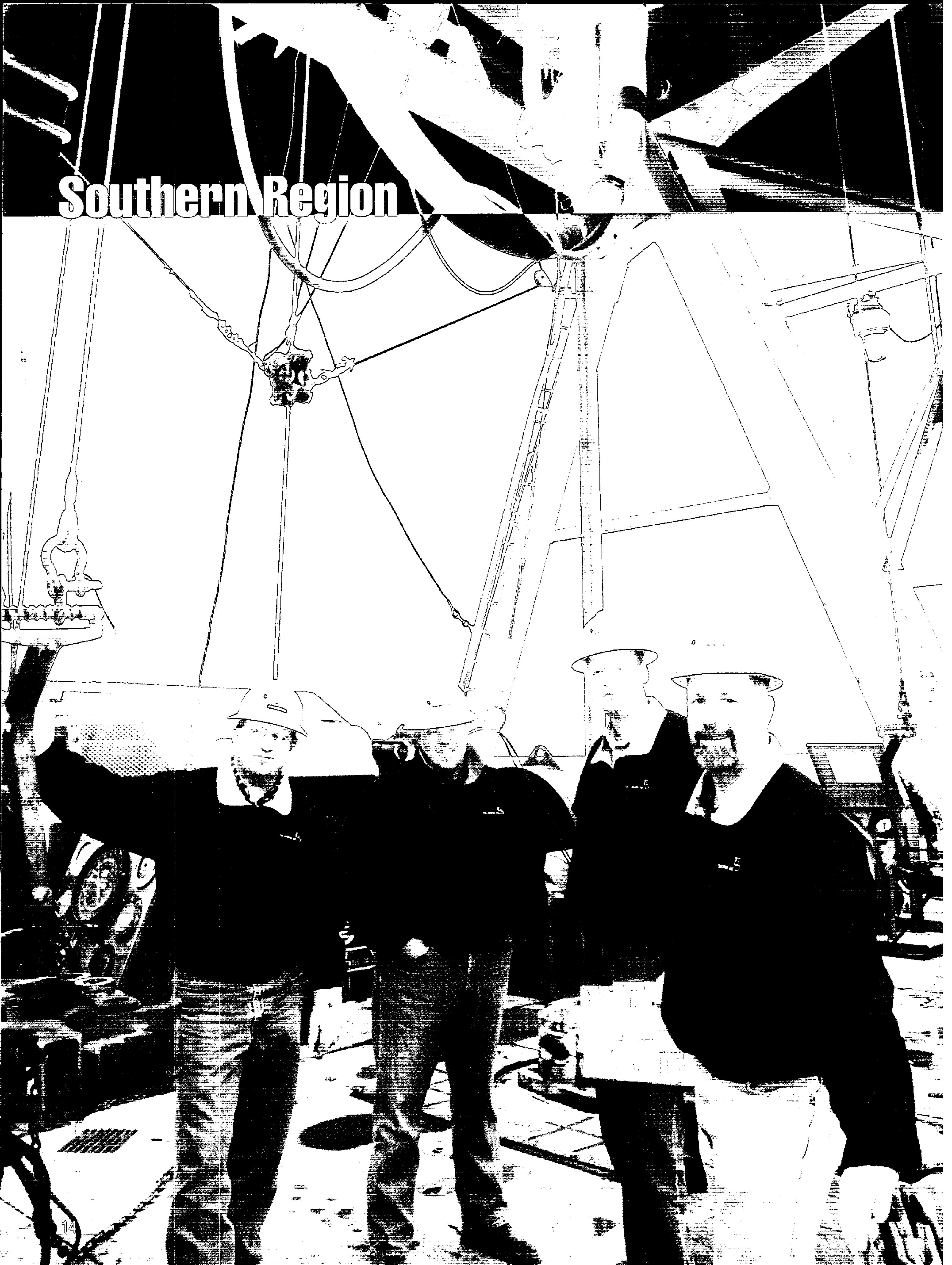
Tom Brown's operations in western Canada, represents 11% of total year end 2002 reserves and 10% of 2002 production.

	2002	2001	2000
Production *(Mmcfepd)*	24.3	23.2	–
Total Gross Acreage *(in thousands)*	540	518	–
Total Net Acreage *(in thousands)*	359	350	–
E&P Capital Spending *(in millions)*	$13.4	$30.8	–
Lease Operating Expense *(per Mcfe)*	$0.55	$0.62	–

In 2002, the Company drilled 13 wells in Canada, primarily in the Carrot Creek and Edson fields. In Canada, the Company produced an average of 24.3 Mmcfepd net in 2002, an increase of 5% over 2001. TBI's Canadian subsidiary, Tom Brown Resources Ltd. (TBRL) has built a strong team over the last 18 months and is now well positioned to be an important part of TBI's future growth.



Southern Region



Texas and Louisiana

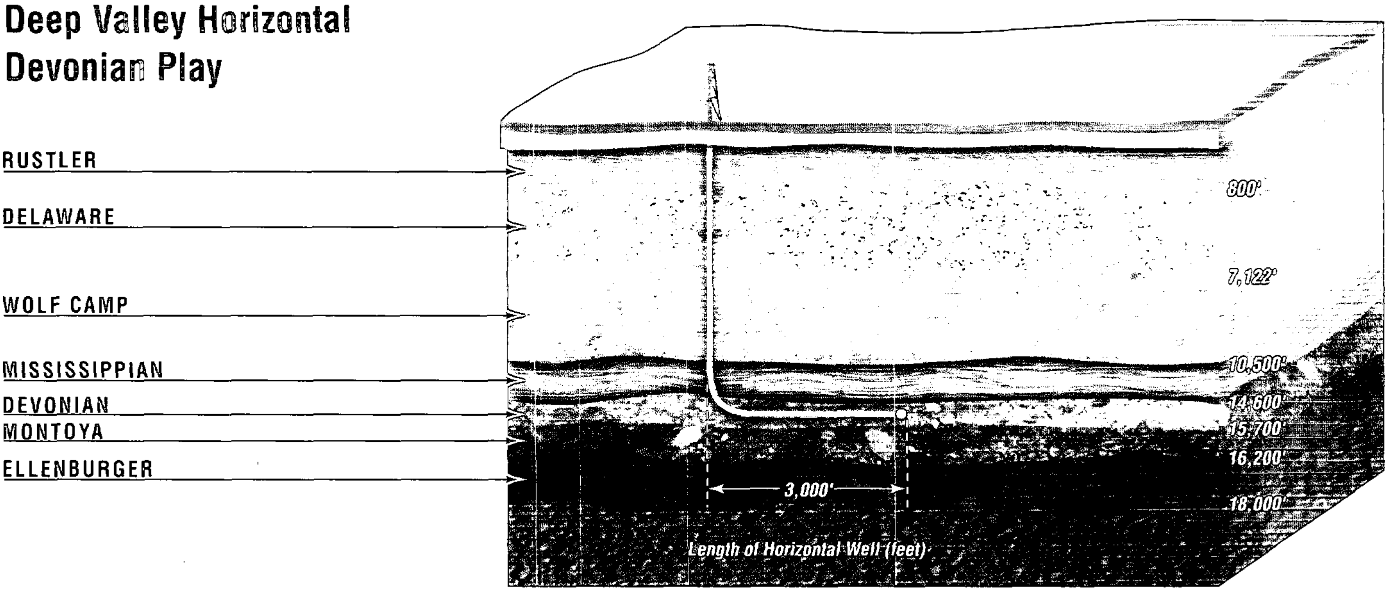
The Southern region represents 15% and 21% of Tom Brown's total reserves and production, respectively. In 2002, the Company drilled or participated in 27 wells in the Southern region and was drilling four wells at year end 2002.

	2002	2001	2000
Production *(Mmcfepd)*	49.2	44.6	45.6
Total Gross Acreage *(in thousands)*	640	614	431
Total Net Acreage *(in thousands)*	356	325	206
E&P Capital Spending *(in millions)*	$49.8	$58.0	$22.5
Lease Operating Expense *(per Mcfe)*	$0.28	$0.35	$0.32

Two of the Company's more significant exploration plays in Texas are the horizontal tight gas Devonian carbonate reservoir in the Permian basin and the horizontal James Lime in the East Texas basin. TBI's Southern Region team members have been involved in exploiting tight gas carbonate reservoirs with horizontal drilling technology from inception in the Permian basin. The team has experience in successful programs in the Devonian, Montoya and Strawn formations, in the Midland, Delaware and Val Verde basins of West Texas. As a result of this considerable knowledge, TBI is uniquely capable of applying industry-leading technology to its current tight carbonate plays at its Deep Valley and James Lime projects and in identifying new opportunities.

In the Deep Valley project area, the Company's Trees Estate #4H well (TBI 50% working interest) began producing in June of 2002 at 10 Mmcfepd from the Devonian formation and as of February 2003 was still producing over 2.5 Mmcfepd, which based upon the Company's reservoir modeling would imply an 8 to 12 Bcfe well. Additionally, approximately six miles northwest of the Trees Estate, the Company drilled the Beefmaster #1H (TBI 50% working interest) and has tested encouraging gas rates from the first of four fracture stimulations. If the Beefmaster is successful, TBI has a significant area in which to begin development of this potentially large resource.

Deep Valley Horizontal Devonian Play



TBI's Southern Region team on location at the Company's Beefmaster well drilling in the Permian basin. Pictured from left to right: Steve Munsell – Drilling Engineer Advisor, Dave Cox – Engineer Advisor, Glenn Bixler - Sr. Geoscientist, Gary MacKay - Landman

Principal Officers

JAMES D. LIGHTNER
Chairman of the Board, Chief Executive Officer and President
Age: 50
Employed with the Company Since: 1999

THOMAS W. DYK
Executive Vice President and Chief Operating Officer
Age: 49
Employed with the Company Since: 1998

DANIEL G. BLANCHARD
Executive Vice President, Chief Financial Officer and Treasurer
Age: 42
Employed with the Company Since: 1999

PETER R. SCHERER
Executive Vice President and General Manager of the Southern Region
Age: 46
Employed with the Company Since: 1982

BRUCE R. DEBOER
Vice President, General Counsel and Secretary
Age: 50
Employed with the Company Since: 1997

RODNEY G. MELLOTT
Vice President – Land and Business Development
Age: 45
Employed with the Company Since: 1999

DOUGLAS R. HARRIS
Vice President – Operations
Age: 48
Employed with the Company Since: 2001

Board Of Directors

JAMES D. LIGHTNER
Chairman of the Board of Directors, Chief Executive Officer and President of Tom Brown, Inc.

JAMES B. WALLACE
Partner in Brownlie, Wallace, Armstrong, and Bander Exploration

THOMAS C. BROWN
Chairman, TMBR/Sharp Drilling Co., Inc.

HENRY GROPPE
Partner in Groppe, Long & Littell

ROBERT H. WHILDEN, JR.
Senior Vice President, General Counsel and Secretary of BMC Software, Inc.

DAVID M. CARMICHAEL
Private Investor

KENNETH B. BUTLER
Vice President of Unocal Gulf Region USA

EDWARD W. LEBARON, JR.
Partner in LeBaron Ranches, L.P.

WAYNE W. MURDY
Chairman and Chief Executive Officer of Newmont Mining Corporation

JOHN C. LINEHAN
Retired Executive Vice President and Chief Financial Officer of Kerr-McGee Corp.

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K/A

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [FEE REQUIRED]

For the Fiscal Year Ended December 31, 2002

or

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [NO FEE REQUIRED]

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 ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. Yes ☐ No ☐

The aggregate market value of the Registrant's Common Stock held by non-affiliates (based upon the last sale price of $24.75 per share as quoted on the New York Stock Exchange) on March 11, 2003 was approximately $975,122,849.

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

CONTENTS

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 westernCanadian 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 which 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. Finding cost was $1.32 per Mcfe for the year from all sources and a 3-year average finding cost of $1.29 per Mcfe. 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. 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, there can be no assurance that the Company will be able to successfully implement its strategy in the future.

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"), in a transaction valued at $95 million, which 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.

Acquisition of Rocky Mountain Assets

In June 2002, the Company purchased certain Rocky Mountain assets located within the Greater Green River Basin of Wyoming for approximately $8.1 million from an undisclosed seller. 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 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. "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 principal asset retained in this process was the Wind River gathering system in one of the Company's core areas. In 2002, the Company liquidated TBIFS and transferred 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.

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.

United States	Years Ended December 31, 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)(1)	$ 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)(2)	$ .57	$ .70	$ .76

Canada	Years Ended December 31, 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)(1)	$ 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)(2)	$ .55	$ .62

(1) Includes the effects of hedging.

(2) Includes lease operating expenses and production taxes. (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.)

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.

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.

EXECUTIVE OFFICERS OF THE COMPANY

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	Since
James D. Lightner	50	Chairman, Chief Executive Officer and President	1999 (President) 2002 (Chairman)
Daniel G. Blanchard	42	Executive Vice President, Chief Financial Officer and Treasurer	1999
Thomas W. Dyk	49	Executive Vice President and Chief Operating Officer	1998
Peter R. Scherer	46	Executive Vice President	1982
Bruce R. DeBoer	50	Vice President, General Counsel and Secretary	1997
Doug R. Harris	48	Vice President—Operations	2001
Rodney G. Mellott	45	Vice President—Land and Business Development	1999

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

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 activities are subject to federal and state laws and regulations governing environmental quality and pollution control. The existence of such regulations has a material effect on the Company's operations but the cost of such compliance has not been material to date. However, the Company believes that the gas and oil industry may experience increasing liabilities and risks under the Comprehensive Environmental Response, Compensation and Liability Act, as well as other federal, state and local environmental laws, as a result of increased enforcement of environmental laws by various regulatory agencies. As an "owner" or "operator" of property where hazardous materials may exist or be present, the Company, like all others in the petroleum industry, could be liable for fines and/or "clean-up" costs, regardless of whether the Company was responsible for the release of any hazardous substances.

Rocno Corporation ("Rocno"), a wholly-owned subsidiary of the Company, is a party to a trust agreement in connection with the environmental clean-up plan for the Sheridan Superfund Site in Waller County, Texas. See Item 3, Legal Proceedings.

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 United States 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 certain issues have been resolved.

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.

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.

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 (the "SEC") 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 SEC 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.

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 SEC.

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
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	

Type of Well	United States			Canada		
	Year ended December 31,					
	2001			2001		
	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	

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

The Company owns a 3,200 square foot building located on a 2.94 acre tract in Midland, Texas. The facility is used primarily for storage of pipe and oilfield equipment.

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 the Comprehensive Environmental Response, Compensation and Liability Act) 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 have 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. The estimate of the total clean-up cost is approximately $30 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 $99,000, 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 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.

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. 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
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:					
EBITDAX(2)	142,557	226,753	177,643	74,438	49,348
Net cash provided by operating activities before changes in working capital(2)	114,400	195,635	159,956	59,821	34,404
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.

(2) EBITDAX reflects income before taxes, plus interest expense, depreciation, depletion and amortization expense, exploration costs and impairments of leasehold costs. EBITDAX and cash flows from operating activities before changes in working capital are not measures determined pursuant to generally accepted accounting principles ("GAAP") and are not intended to be used in lieu of GAAP presentations of net income or cash flows from operating activities. EBITDAX for 1998 excludes $51.3 million for impairment of gas and oil properties, which were non-cash charges. EBITDAX for 2002 and 2001 excludes the cumulative effect of changes in accounting principles.

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*

FORWARD-LOOKING STATEMENTS AND RISK

Certain statements in this report, including statements of the future plans, objectives, and expected performance of the Company, are forward-looking statements that are dependent on certain events, risks and uncertainties that may be outside the Company's control which could cause actual results to differ materially from those anticipated. Some of these include, but are not limited to, economic and competitive conditions, inflation rates, legislative and regulatory changes, financial market conditions, political and economic uncertainties, future business decisions, and other uncertainties, all of which are difficult to predict.

There are numerous uncertainties inherent in estimating quantities of proven oil and gas reserves and in projecting future rates of production and timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserves and production estimates. The drilling of exploratory wells can involve significant risks including those related to timing, success rates and cost overruns. Lease and rig availability, complex geology and other factors can affect these risks. Future oil and gas prices also could affect results of operations and cash flows.

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 us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. Our significant accounting policies are described in the notes to our consolidated financial statements. We have identified certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management. We analyze our 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 base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe 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 and there can be no assurance that impairments will not be required in the future.

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 our cash flows in an environment of volatile gas and oil prices and to manage the exposure to commodity price risk. We recognize 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 our hedging derivatives requires substantial judgment. The fair values of our 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.

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). In conjunction with the January 2001 Stellarton Energy acquisition, the Company allocated $20 million of the purchase price to goodwill. The fair value test performed to evaluate the carrying value of this business segment and the recorded goodwill as required by SFAS No. 142 resulted in the recognition of a non-cash charge of $18.1 million. 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, previously Tom Brown, Inc.'s 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
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 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 for $2.0 million. In November 2002, the Company sold certain oil and gas properties located in Colorado 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. 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
			(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 had entered into an agreement with a 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. Under certain circumstances, the Company has the right but not the obligation to purchase the processing facility from the third party during the term of this agreement.

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.

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

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	December 31, 2001
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 13,555	$ 15,196
Accounts receivable	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
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 12)		
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
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				
					(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 and exploration 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)
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.

(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. 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 and transferred 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

(1) Nature of Operations (Continued)

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.

(2) Summary of Significant Accounting Policies (Continued)

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.

(2) Summary of Significant Accounting Policies (Continued)

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 and conducted a fair value based test to evaluate the goodwill originally recorded in conjunction with the January 2001 Stellarton Energy Corporation acquisition. 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. Had SFAS No. 142 been effective for the year ended December 31, 2001, the Company's net income would have increased by $.9 million, or $.02 per share, as the result of the elimination of goodwill amortization.

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 SFAS No. 143 on January 1, 2003. Upon adoption of SFAS No. 143, the Company will record a discounted liability of $14.5 million for the

(2) Summary of Significant Accounting Policies (Continued)

future retirement obligation, increase net property and equipment by $13.0 million and record a charge of $1.0 million (net of a deferred tax benefit of $.5 million) as the cumulative effect of the change in accounting principle. The majority of the asset retirement obligation to be recognized will relate to the projected cost to plug and abandon gas and oil wells. Liabilities will also be recorded for processing plants, compressors and other field facilities.

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets". SFAS No. 144 supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of". SFAS No. 121 did not address the accounting for a segment of a business accounted for as a discontinued operation which resulted in two accounting models for long-lived assets to be disposed of. SFAS No. 144 establishes a single accounting model for long-lived assets to be disposed of by sale and requires that those long-lived assets be measured at the lower of carrying amount or fair value less cost to sell, whether reported in continuing operations or in discontinued operations. SFAS No. 144 is effective for fiscal years beginning after December 15, 2001. The Company adopted SFAS No. 144 on January 1, 2002. There was no impact on the Company's financial position or results of operations upon adoption of SFAS No. 144.

In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." SFAS 146 nullifies the guidance of the Emerging Issues Task Force (EITF) Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." SFAS 146 requires that a liability for a cost that is associated with an exit or disposal activity be recognized when the liability is incurred. SFAS 146 also establishes that fair value is the objective for the initial measurement of the liability. The provisions of SFAS 146 are required for exit or disposal activities that are initiated after December 31, 2002. The adoption of this statement did not impact the Company's financial position or results of operations.

In November 2002, the FASB issued Financial Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, including Indirect Guarantee of Indebtedness of Others" (FIN 45). FIN 45 requires that upon issuance of a guarantee, the guarantor must recognize a liability for the fair value of the obligation it assumes under that guarantee. FIN 45's provisions for initial recognition and measurement should be applied on a prospective basis to guarantees issued or modified after December 31, 2002. The guarantor's previous accounting for guarantees that were issued before the date of FIN 45's initial application may not be revised or restated to reflect the effect of the recognition and measurement provisions of the Interpretation. The disclosure requirements are effective for financial statements of both interim and annual periods that end after December 15, 2002. The Company is not a guarantor under any significant guarantees and thus this interpretation is not expected to have a significant effect on our financial position or results of operations.

In December 2002, the FASB issued SFAS 148, "Accounting for Stock-Based Compensation—Transition and Disclosure." SFAS No. 148 amends FASB Statement No. 123, "Accounting for Stock-Based Compensation" to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, this Statement amends the disclosure for stock-based employee compensation and the effect of the method used on the reported results. The provisions of SFAS 148 are effective for financial statements with fiscal years

(2) Summary of Significant Accounting Policies (Continued)

ending after December 15, 2002. The adoption of this statement did not impact the Company's financial position or results of operations.

In January 2003, the FASB issued Financial Interpretation No. 46, "Consolidation of Variable Interest Entities—an interpretation of ARB No. 51" (FIN 46). FIN 46 is an interpretation of Accounting Research Bulletin 51, "Consolidated Financial Statements", and addresses consolidation by business enterprises of variable interest entities (VIE's). The primary objective of FIN 46 is to provide guidance on the identification of, and financial reporting for, entities over which control is achieved through means other than voting rights; such entities are known as VIE's. FIN 46 requires an enterprise to consolidate a variable interest entity if that enterprise has a variable interest that will absorb a majority of the entity's expected losses if they occur, receive a majority of the entity's expected residual return if they occur, or both. An enterprise shall consider the rights and obligations conveyed by its variable interests in making this determination. This guidance applies immediately to variable interest entities created after January 31, 2003, and to variable interest entities in which an enterprise obtains an interest after that date. It applies in the first fiscal year or interim period beginning after June 15, 2003, to variable interest entities in which an enterprise holds a variable interest that it acquired before February 1, 2003. The Company does not hold any interest in VIE's that would be impacted by FIN 46. Therefore, the adoption of this interpretation will not impact the Company's financial position or results of operations.

Income Taxes

The Company provides for income taxes using the liability method under which deferred income taxes are recognized for the tax consequences of "temporary differences" by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. The effect on deferred taxes of a change in tax laws or tax rates is recognized in income in the period such changes are enacted.

Stock-Based Compensation

The Company accounts for employee stock-based compensation using the intrinsic value method prescribed by Accounting Principles Board (APB) Opinion No. 25 "Accounting for Stock Issued to Employees" and related interpretations under which no compensation cost has been recognized for grants of options under the Company's stock option plans. Alternatively, if compensation costs for

(2) Summary of Significant Accounting Policies (Continued)

these plans had been determined in accordance with SFAS No. 123, the Company's net income and net income per common share would approximate the following pro forma amounts:

	Years Ended December 31,		
	2002	2001	2000
	(In thousands, except per share amounts)		
Net (loss) income			
As reported	$ (8,177)	$69,503	$65,703
Add: Compensation cost included in reported net (loss) income (net of tax) (1)	—	2,361	—
Deduct: Stock-based employee compensation expense determined under fair value based method for all awards (net of tax)	(5,090)	(5,294)	(2,010)
Pro forma	$(13,267)	$66,570	$63,693
Basic net (loss) income per common share:			
As reported	$ (.21)	$ 1.78	$ 1.79
Pro forma	$ (.34)	$ 1.71	$ 1.74
Diluted net (loss) income per common share:			
As reported	$ (.20)	$ 1.73	$ 1.76
Pro forma	$ (.33)	$ 1.65	$ 1.70

(1) Compensation cost in 2001 is the result of accelerated vesting of options

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles require management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements. Such estimates and assumptions also affect the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates affecting these financial statements include the estimate of proved oil and gas reserve volumes and the related present value of estimated future net revenues to be received therefrom.

Net Income Per Common Share

Basic earnings per share ("EPS") is calculated by dividing net income attributable to common stock by the weighted average number of common shares outstanding during the period including the weighted average impact of the shares of common stock issued during the year from the date of issuance. Diluted EPS calculations also give effect to all dilutive potential common shares outstanding during the period.

(2) Summary of Significant Accounting Policies (Continued)

The following is a reconciliation of the numerators and denominators used in the calculation of basic and diluted EPS for the years ended December 31, 2002, 2001 and 2000:

	2002			2001			2000		
	Net Loss	Shares	Per Share Amount	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
	(In thousands, except per share amounts)								
Basic EPS:									
Net (Loss) Income Attributable to Common Stock and Share Amounts	$(8,177)	39,217	$(.21)	$69,503	38,943	$1.78	$65,703	36,664	$1.79
Dilutive Securities:									
Stock Options	—	1,110	—	—	1,284	—	—	473	—
Convertible preferred stock	—	—	—	—	—	—	875	760	—
Diluted EPS:									
Net (Loss) Income Attributable to Common Stock and Diluted Share Amounts	$(8,177)	40,327	$(.20)	$69,503	40,227	$1.73	$66,578	37,897	$1.76

Options to purchase 1,688,000 and 1,180,000 shares of common stock in 2002 and 2001 were excluded in the computation of diluted earnings per share because the option exercise price was greater than the average market price of the Company's common stock. No options were excluded in 2000.

Cash Equivalents

The Company considers investments with an original maturity of three months or less when purchased to be cash equivalents.

Comprehensive Income

Comprehensive income represents all non-shareholder related changes in equity of an entity during the reporting period, including net income and charges directly to equity which are excluded from net income. At December 31, 2002 and 2001, the reconciling items between net income as reflected in the statement of operations and comprehensive income were an unrealized loss on marketable securities, a translation loss, and an unrealized loss on derivatives. The only reconciling items between net income as reflected in the statement of operations and comprehensive income for the year ended December 31, 2000 was an unrealized loss on marketable securities.

(3) Acquisitions and Divestitures

Acquisition of Stellarton

On January 12, 2001, the Company completed an acquisition of 97.2% of the outstanding common shares of Stellarton. The remaining shares of Stellarton were then subsequently acquired pursuant to the compulsory acquisition provisions of the Business Corporation Act (Alberta). Including assumed debt of approximately $16.8 million, this business combination had a value of approximately $95 million and was accounted for as a purchase. The purchase price exceeded the fair value of the net assets of Stellarton by $20 million which was recorded as goodwill, a portion of which was amortized in 2001 on a straight-line basis utilizing a twenty year life. Effective January 1, 2002 the Company adopted SFAS

(3) Acquisitions and Divestitures (Continued)

No. 142, "Goodwill and Other Intangible Assets" and expensed the unamortized goodwill of $18.1 million associated with this change in accounting principle. The net proved reserves associated with the Stellarton properties were estimated to be 75.8 billion cubic feet equivalent of gas (Bcfe) (unaudited) as of the closing date. The results of operations of Stellarton are included with the results of the Company from January 12, 2001 (closing date) forward.

The purchase price was allocated as follows (in thousands):

Cash paid for acquisition:	
Long-term debt incurred	$ 74,500
Long-term debt assumed	16,800
Direct acquisition costs	3,107
Total cash paid	94,407
Allocation of acquisition costs:	
Oil and gas properties—proved	(117,000)
Unproved properties	(9,975)
Deferred income taxes	36,375
Gas sales contracts assumed	10,825
Net working capital deficit assumed	5,368
Goodwill	$ 20,000

In the acquisition costs identified above, the Company recorded a deferred income tax liability of $36.4 million to recognize the difference between the historical tax basis of the Stellarton assets and the acquisition costs recorded for book purposes. The recorded book value of the proved oil and gas properties was increased and goodwill was recorded to recognize this tax basis differential.

The gas sales contracts assumed in conjunction with the acquisition represented contractual obligations associated with the sale of natural gas at fixed prices below the then current market prices. These contracts were subsequently purchased (for an amount approximately equal to the original liability recorded) and cancelled in the quarter ended June 30, 2001.

Pro Forma Results of Operations (Unaudited)

The following table reflects the unaudited pro forma results of operations for the twelve months ended December 31, 2001 and 2000 as though the Stellarton Acquisition had occurred on January 1 of each period presented. The pro forma amounts are not necessarily representative of the results that may be reported in the future.

	Years Ended December 31,	
	2001	2000
	(In thousands, except per share data)	
Revenues	$328,267	$278,794
Net Income	69,503	64,008
Basic net income per share	1.78	1.75
Diluted net income per share	1.73	1.71

Acquisition of Rocky Mountain Assets

In June 2002, the Company purchased certain Rocky Mountain assets located within the Greater Green River Basin of Wyoming for approximately $8.1 million from an undisclosed seller. 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 (unaudited).

In June 2000, the Company purchased an additional working interest in a field operated by the Company in the Wind River Basin in Wyoming. The acquired interests included an estimated 24.0 Bcfe of proved reserves (unaudited) purchased for total consideration of $15.2 million net of normal closing adjustments.

Property Sales

During May 2001, the Company sold its interest in oil and gas properties primarily located in Oklahoma, with a net book value of $14.4 million, for net cash proceeds of $24.5 million. The resulting gain of $10.1 million is reflected in the Consolidated Statement of Operations.

In June and October 2001, the Company sold certain of the gathering and processing assets originally received in the Wildhorse distribution completed in 2000 for net cash proceeds of $24.0 million. The systems sold were considered non-strategic to the Company's operations.

In April 2002, the Company sold its interest in oil and gas properties, located in the Powder River Basin of Wyoming, 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 sold certain oil and gas properties located primarily in Louisiana for $2.0 million and in November 2002, certain oil and gas properties located primarily in Colorado were sold 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.

(4) Debt

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 and other restrictions 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 in 2002 and at December 31, 2002.

(5) Taxes

The income tax (expense) benefit was different from amounts computed by applying the statutory Federal and State income tax rates to income before income taxes for the following reasons:

	2002	2001	2000
		(In thousands)	
Tax expense at 35% of income before income taxes and change in accounting principle	$(4,598)	$(36,961)	$(37,225)
State tax expense net of federal benefit	(263)	(2,112)	(2,127)
Franchise and other taxes	(614)	(486)	(1,614)
Canadian Crown payments (net of Alberta Royalty Tax Credit) not deductible for tax purposes	(2,879)	(4,136)	—
Canadian resource allowance	2,699	3,556	—
Canadian expenses deductible in the United States	1,578	1,845	—
Canadian Large Corporation Tax	(285)	(335)	—
Adjustments to prior periods due to filed returns	397	502	—
Valuation allowance adjustment	—	—	1,953
Enterprise zone tax credits	1,018	—	—
Other	(263)	—	(767)
Total income tax expense	$(3,210)	$(38,127)	$(39,780)

Deferred income taxes result from recognizing income and expenses at different times for financial and tax reporting. In the United States, the largest differences are created by the tax effect of the capitalization of certain development, exploration and other costs under the successful efforts method of accounting for book purposes. In Canada, differences result in part from accelerated cost recovery of oil and gas capital expenditures for tax purposes.

(5) Taxes (Continued)

The components of the net deferred tax liability by geographical segment at December 31, 2002 and 2001 were as follows:

	December 31, 2002		
	United States	Canada	Total
	(In thousands)		
Deferred tax assets:			
Net operating loss carryforward	$ 9,580	$ 2,542	$ 12,122
Percentage depletion carryforward	2,520	—	2,520
Alternative minimum tax credit carryforward	4,831	—	4,831
Derivative contracts to be settled in a future period	3,176	799	3,975
Other	1,031	—	1,031
Total gross deferred tax assets	21,138	3,341	24,479
Deferred tax liabilities:			
Property and equipment	(61,502)	(36,741)	(98,243)
Other	(203)	—	(203)
Total gross deferred tax liabilities	(61,705)	(36,741)	(98,446)
Net deferred tax liabilities	$(40,567)	$(33,400)	$(73,967)

	December 31, 2001		
	United States	Canada	Total
	(In thousands)		
Deferred tax assets:			
Net operating loss carryforward	$ 6,918	$ 302	$ 7,220
Percentage depletion carryforward	2,178	—	2,178
Alternative minimum tax credit carryforward	5,190	—	5,190
Other	300	—	300
Total gross deferred tax assets	14,586	302	14,888
Deferred tax liabilities:			
Property and equipment	(55,119)	(34,558)	(89,677)
Other	(405)	—	(405)
Total gross deferred tax liabilities	(55,524)	(34,558)	(90,082)
Net deferred tax liabilities	$(40,938)	$(34,256)	$(75,194)

The Alternative Minimum Tax (AMT) credit carryforward available to reduce future U.S. Federal regular taxes aggregated $4.8 million at December 31, 2002. This amount may be carried forward indefinitely. U.S. Federal regular and AMT net operating loss carryforwards at December 31, 2002 were approximately $25.9 and $19.0 million, respectively, and will expire in 2019. AMT net operating loss carryforwards can be used to offset 90% of AMT income in future years (the Job Creation and Worker Assistance Act of 2002 allowed for 100% of the AMT net operating loss carryforwards to be offset against AMT income for 2001 and 2002.) Realization of the benefit of these carryforwards is dependent upon the Company's ability to generate taxable earnings in future periods.

Percentage depletion carryforwards available to reduce future U.S. Federal taxable income aggregated $7.2 million at December 31, 2002. This amount may be carried forward indefinitely.

(5) Taxes (Continued)

Canadian net operating losses available to reduce future Canadian Federal income taxes were \$6.0 million (\$9.4 million CDN) at December 31, 2002 and expire in 2008.

Canadian tax pools relating to the exploration, development and production of oil and natural gas available to reduce future Canadian Federal income taxes aggregate approximately \$47.0 million (\$74.3 million CDN) at December 31, 2002. These pool balances are deductible on a declining balance basis ranging from 10% to 100% of the balance annually. The amounts may be carried forward indefinitely.

In conjunction with the acquisition of Stellarton in January 2001, the purchase price allocation resulted in a difference between the book and tax basis of approximately U.S. \$63 million. Based upon Stellarton's historical tax rate of 43%, a deferred tax liability of approximately \$36.4 million was recognized.

(6) Trading Activities

The Company engages in natural gas trading activities which involve purchasing natural gas from third parties and selling natural gas to other parties. These transactions are typically short-term in nature and involve positions whereby the underlying quantities generally offset. The Company also markets a significant portion of its own production. Marketing and trading income associated with these activities is presented on a net basis in the financial statements. The Company's gross trading activities are summarized below.

	Years Ended December 31,		
	2002	2001	2000
		(In thousands)	
Revenues	\$55,162	\$123,767	\$111,756
Operating expenses	53,623	122,776	108,370
Net trading margin	1,539	991	3,386
Marketing margin on the Company's production	3,737	900	2,455
Marketing and trading revenues—net	\$ 5,276	\$ 1,891	\$ 5,841

(7) Stockholders' Equity

Common Stock

The Company's Common Stock is \$.10 par value per share. There were 55,000,000 authorized shares of Common Stock at December 31, 2002 of which 39,261,191 shares and 39,127,649 shares were outstanding at December 31, 2002 and 2001, respectively.

Rights Plan

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

(7) Stockholders' Equity (Continued)

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. 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.

Preferred Stock

In January 1996, in connection with the KNPC acquisition, the Company issued 1,000,000 shares of its $1.75 Convertible Preferred Stock, Series A (the "Preferred Stock") to the seller. There are 2,500,000 shares of Preferred Stock authorized. The holder of the Preferred Stock was entitled to receive cumulative dividends at the annual rate of $1.75 per share, payable in cash quarterly on the fifteenth day of March, June, September and December in each year.

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 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 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. Dividends on the Preferred Stock were paid through June 14, 2000 and did not accrue after the June 15, 2000 exchange date. The Preferred Stock is no longer outstanding.

(8) Benefit Plans

1989 Plan

The Company's 1989 Stock Option Plan expired in December 1999. As of December 31, 2002, options to purchase 336,200 shares of the Company's common stock were outstanding under the 1989 Plan. These options will expire between 2003 and 2008 if not previously exercised.

1993 Plan

In February 1993, the Board of Directors adopted the Company's 1993 Stock Option Plan (the "1993 Plan"). The 1993 Plan provides for issuance of options to certain employees and directors to purchase shares of Common Stock. In November 1999, the aggregate number of shares of Common Stock that may be issued under the 1993 Plan was increased from 2,700,000 shares to 3,200,000 shares. The aggregate number of shares was subsequently increased to 4,100,000 in January 2001. The exercise price, vesting and duration of the options may vary and will be determined at the time of issuance. Options to purchase 2,779,000 shares of the Company's Common Stock were outstanding under this plan as of December 31, 2002.

1999 Plan

The 1999 Long Term Incentive Plan (the "1999 Plan") was adopted by the Board of Directors on February 17, 1999, and approved by the stockholders on May 20, 1999. The 1999 Plan provides for the grant of stock options, restricted stock awards, performance awards and incentive awards. There were option grants made to purchase 447,400, 378,700 and 490,000 shares of the Company's Common Stock in 2002, 2001 and 2000, respectively. The aggregate number of shares of common stock, which may be issued under the 1999 Plan, may not exceed 2,000,000 shares. The maximum value of any performance award granted to any one individual during any calendar year may not exceed $500,000. The exercise price, vesting and duration of any grants may vary and will be determined at the time of issuance. Options to purchase 1,197,500 shares of the Company's Common Stock were outstanding under this plan as of December 31, 2002.

A summary of the status of the plans described above, as of the dates indicated, and the changes during the years then ended, is presented in the table and narrative below:

	Years Ended December 31,					
	2002		2001		2000	
	Shares Under Option	Weighted Average Exercise Price	Shares Under Option	Weighted Average Exercise Price	Shares Under Option	Weighted Average Exercise Price
	(Shares in thousands)					
Outstanding, beginning of year	3,919	19.60	3,412	$14.52	4,139	$13.77
Granted	700	26.61	1,531	29.56	852	15.14
Exercised	(152)	13.63	(778)	14.50	(1,378)	12.67
Cancellations	(154)	23.44	(246)	26.45	(201)	14.77
Outstanding, end of year	4,313	20.81	3,919	19.60	3,412	14.52
Exercisable, end of year	1,941	16.92	1,331	14.24	1,659	14.22
Available for grant, end of year	759		1,305		1,722	

The weighted average fair value of options granted during the years ended December 31, 2002, 2001, and 2000 was $24.33, $18.12, and $9.78, respectively. The fair value of each option is estimated as of the date of grant using the Black-Scholes option-pricing model with the following weighted-average assumptions used for grants in 2002, 2001, and 2000, respectively: (i) risk-free interest rates of 3.47, 4.46 and 6.25 percent; (ii) expected lives of 7.0, 7.0 and 7.0 years, (iii) expected volatility of 126.0, 56.0 and 53.7 percent, and (iv) no dividend yields.

(8) Benefit Plans (Continued)

The following table summarizes information about stock options outstanding at December 31, 2002:

Range of Exercise Prices	OPTIONS OUTSTANDING			OPTIONS EXERCISABLE	
	Number of Shares Under Outstanding Options	Weighted Average Life (Years)	Weighted Average Exercise Price	Number of Shares Under Exercisable Options	Weighted Average Exercise Price
			(Shares in thousands)		
$3.81 to $12.625	531	5.50	$11.65	328	$11.10
$12.6875 to $15.25	931	4.62	13.72	623	13.88
$15.6875 to $23.75	1,099	6.34	18.19	702	16.93
$23.89 to $30.13	935	8.88	27.09	81	27.41
$31.00 to $34.00	817	8.09	31.17	207	31.17
	4,313	6.75	20.81	1,941	16.92

In January 2001, the Company's Chairman and Chief Executive Officer resigned to become the United States Secretary of Commerce. The Company accelerated the vesting of 228,300 of his outstanding stock options upon his resignation and as a result of this modification to the initial terms of these stock options, a new measurement date was established. Based upon the difference between the market price of the Company's stock on the date the stock options were amended and the exercise price of the stock options, a non-cash pre-tax charge to earnings of $3.8 million was recognized.

Employee Benefit Plans

Effective January 1, 2000, the Company adopted a 401(k) retirement plan that superseded a profit sharing plan and KSOP plan previously in existence. The Company has a policy to match employee contributions to the plan, at its discretion. As of December 31, 2002, the Company's policy was to match 100% of the employee contribution up to a total match of seven percent of the employee's salary. The match for the years ended December 31, 2002, 2001 and 2000, was approximately $1,403,000, $864,000 and $492,000, respectively.

(9) Financial Instruments

The carrying values of trade receivables and trade payables approximated market value. The carrying amounts of cash and cash equivalents approximated fair value due to the short maturity of these instruments. The carrying value of debt approximated fair value because the interest rate is variable and is reflective of current market conditions.

Derivative Instruments and Hedging Activities

The Company periodically enters into natural gas and crude oil futures contracts with counter parties to hedge the price risk associated with a portion of its production. These derivatives are not held for trading purposes. To the extent that changes occur in the market prices of natural gas and oil, the Company is exposed to market risk on these open contracts. This market risk exposure is generally offset by the gain or loss recognized upon the ultimate sale of the commodity hedged.

At December 31, 2002 the Company had a current derivative liability of $10.9 million, a tax deferred tax asset of $4.0 million and accumulated other comprehensive loss of approximately $6.5 million. As of December 31, 2001, the Company had no open derivative contracts.

In April and May 2002, the Company entered into several natural gas costless collars (put and call options) that were based on separate regional price indexes where the Company physically delivers its natural gas. The collars are designated as hedges of production from May through December 2003. In July and August 2002, the Company entered into several natural gas price swaps and corresponding basis swap transactions that together fixed the price the Company will receive for a portion of its natural gas production. These swaps were designed as hedges of production from September 2002 through October 2003 in certain of the regions where the Company physically delivers its gas. A derivative loss of $0.4 million was recognized on the basis portion of these transactions prior to designating the basis contracts as hedges when the corresponding natural gas price swap contracts were executed. In December 2002, the Company entered into additional costless collar arrangements (put and call options) that were based on several of the regional price indexes where the Company physically delivers its natural gas. The collars are designed as hedges of production from January 2003 through October 2003.

As a result of the above transactions, 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 2002 contract periods. These contracts effectively fixed a price differential into the Mid Continent market at a weighted average price $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 gains and losses directly to earnings. As of December 31, 2002, the Company recognized derivative losses of $2.1 million on these contracts all of which were settled.

The Company recognized an increase in gas and oil sales of $17.4 million in 2001 as a result of cash flow hedges. In 2002, cash flow hedges had no impact on gas and oil sales. The Company recognized a net loss of $2.4 million in 2002 and a gain of $.9 million in 2001 as a result of derivatives that did not qualify as hedges in those years.

In December 2000, the Company entered into natural gas basis swaps covering essentially the same time period of natural gas costless collars also entered into in December 2000. Under SFAS 133, these basis swaps did not qualify for hedge accounting. Accordingly, upon adoption of SFAS 133, these basis swaps resulted in the recognition of derivative gains of $2.0 million, recorded as cumulative effect of a change in accounting principle, (net of the deferred tax liability of $1.2 million) and a derivative asset of $3.2 million. During the year ended December 31, 2001, a $.9 million gain was recognized in conjunction with the change in the value of these contracts and cash receipts of $4.1 million were received upon settlement of the swaps.

(10) Related Parties and Significant Customers

Related Parties

One of the Company's directors participates (either individually or indirectly through various entities) with the Company and other unrelated investors in the drilling, development and operation of gas and oil properties. Receivables and payables arising from related party transactions are non-interest bearing and are settled in the normal course of business with terms which, in management's opinion, are similar to those with other joint owners.

The Company paid approximately $38,000, $41,000 and $44,000 during the years ended December 31, 2002, 2001 and 2000, respectively, to a consulting firm that has a partner who serves as a director of the Company.

The Company participates in exploration activity with a partnership, one of whose partner is a director of the Company. During the years ended December 31, 2002, 2001, and 2000, the Company billed $111,000, $621,000 and $612,000, respectively, to such partnership for their share of certain leasehold and drilling costs.

In addition, a director of the Company is also a director of a drilling contractor that has performed drilling services on wells operated by the Company. The fees charged for these services were $787,000 for the year ended December 31, 2000. No fees were paid in 2002 or 2001.

In management's opinion, the above described transactions and services were provided on the same terms as could be obtained from non-related sources.

Significant Customers

Gas and oil sales to ConocoPhillips, Inc. accounted for 17%, 11% and 11% of gas and oil sales for the years ended December 31, 2002, 2001 and 2000, respectively. Because there are numerous other parties available to purchase the Company's production, the Company believes the loss of this purchaser would not materially affect its ability to sell natural gas or crude oil.

Concentration of Credit Risk

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.

Purchaser Default

The Company's previous purchaser of its natural gas liquids in the Paradox Basin of Colorado and Utah defaulted on payments owed the Company totaling $6.2 million in 2002. 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

(10) Related Parties and Significant Customers (Continued)

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.

(11) Segment Information

The Company operates in three reportable segments: (i) gas and oil exploration and development in the United States and Canada, (ii) marketing, gathering and processing and (iii) drilling. The long-term financial performance of each of the reportable segments is affected by similar economic conditions.

The Company's gas and oil exploration and development segment operates primarily 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 of west Texas, the Permian Basin of west Texas and southwestern New Mexico, the east Texas basin and the western sedimentary basin of Canada. The marketing, gathering and processing activities of the Company are conducted primarily in the Rocky Mountain region. The drilling segment operates under the name of Sauer Drilling Company and serves the drilling needs of operators in the central Rocky Mountain region in addition to drilling for the Company.

The accounting policies of the segments are the same as those described in Note 2 of the Notes to Consolidated Financial Statements. The Company evaluates performance based on profit or loss from operations before income taxes, accounting changes, nonrecurring items and interest income and expense.

The Company accounts for intersegment sales transfers as if the sales or transfers were to third parties, that is, at current prices.

(11) Segment Information (Continued)

The following tables present information related to the Company's reportable segments (in thousands):

	As of or Year Ended December 31, 2002				
	Gas & Oil Exploration & Development (United States)	Gas & Oil Exploration & Development (Canada)	Marketing, Gathering & Processing	Drilling	Total Segments
Revenues from external purchasers	$99,948	$27,774	$178,782	$14,347	$320,851
Intersegment revenues	66,379	—	11,625	6,774	84,778
Depreciation, depletion and amortization	72,788	14,499	2,594	1,426	91,307
Segment profit	4,314	4,222	12,598	308	21,442
Assets	667,446	149,589	67,442	16,376	900,833
Capital and exploration expenditures	144,882	13,278	4,705	943	163,808

	As of or Year Ended December 31, 2001				
	Gas & Oil Exploration & Development (United States)	Gas & Oil Exploration & Development (Canada)	Marketing, Gathering & Processing	Drilling	Total Segments
Revenues from external purchasers	$162,158	$30,133	$266,386	$14,828	$473,505
Intersegment revenues	83,991	—	6,556	12,777	103,324
Depreciation, depletion and amortization	55,692	14,079	2,951	1,649	74,371
Segment profit	85,932	5,593	9,671	5,141	106,337
Assets	644,483	165,399	59,333	19,606	888,821
Capital and exploration expenditures	316,934	31,280	9,300	5,237	362,751

	As of or Year Ended December 31, 2000			
	Gas & Oil Exploration & Development (United States)	Marketing Gathering & Processing	Drilling	Total Segments
Revenues from external purchasers	$153,026	$229,100	$11,472	$393,598
Intersegment revenues	55,150	—	6,309	61,459
Depreciation, depletion and amortization	46,853	2,959	1,707	51,519
Segment profit	99,243	12,165	1,635	113,043
Assets	545,639	110,438	13,612	669,689
Capital and exploration expenditures	132,117	16,347	2,725	151,189

(11) Segment Information (Continued)

The following tables reconcile segment information to consolidated totals:

	As of or Years Ended December 31,		
	2002	2001	2000
		(In thousands)	
Revenues			
Revenue from external purchasers	$320,851	$473,505	$393,598
Marketing and trading expenses offset against related revenues for net presentation	(102,636)	(170,774)	(148,480)
Gain on sale of property	4,114	10,078	—
Loss on marketable security	(600)	—	—
Intersegment revenues	84,778	103,324	61,459
Intercompany eliminations	(70,862)	(89,809)	(52,667)
Total consolidated revenues	$235,645	$326,324	$253,910
Profit			
Total reportable segment profit	$ 21,442	$106,337	$113,043
Interest expense and other	(9,726)	(6,139)	(5,967)
Gain on sale of property	4,114	10,078	—
Loss on marketable security	(600)	—	—
Eliminations and other	(2,094)	(4,672)	(718)
Income before income taxes and cumulative effect of change in accounting principles	$ 13,136	$105,604	$106,358
Depreciation, depletion and amortization			
Total reportable segment depreciation, depletion and amortization	$ 91,307	$ 74,371	$ 51,519
Elimination and other	—	—	(1,102)
	$ 91,307	$ 74,371	$ 50,417
Assets			
Total reportable segment assets	$900,833	$888,821	$669,689
Elimination and other	(49,881)	(43,846)	(40,154)
	$850,952	$844,975	$629,535

(12) Commitments and Contingencies

The Company's operations are subject to numerous governmental regulations that may give rise to claims against the Company. In addition, the Company is a defendant in various lawsuits generally incidental to its business. The Company does not believe that the ultimate resolution of such litigation will have a material adverse effect on the Company's financial position, results of operations or cash flows.

The Company is 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.

(12) Commitments and Contingencies (Continued)

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.

Lease Commitments

At December 31, 2002, the Company had long-term leases through 2004 covering certain of its facilities and equipment. The minimum rental commitments under non-cancelable operating leases with lease terms in excess of one year are as follows:

Years Ending December 31,	Commitment Amount (In thousands)
2003	$1,639
2004	348
2005	146
Thereafter	49
	$2,182

Total rental expense incurred for the years ended December 31, 2002, 2001 and 2000, was approximately $1,648,000, $1,558,000 and $1,447,000, respectively, all of which represented minimum rentals under non-cancelable operating leases.

Firm Transportation Commitments

The Company's obligation for firm transportation commitments in effect at December 31, 2002 for the next five years and thereafter is as follows:

Years Ending December 31,	Commitment Amount (In thousands)
2003	$ 5,274
2004	3,576
2005	2,810
2006	1,052
2007	368
Thereafter	228
	$13,308

(12) Commitments and Contingencies (Continued)

Subsequent to December 31, 2002, the Company entered into additional firm transportation agreements to market its production in the Rocky Mountain region. The additional commitments for the next five years and thereafter are as follows:

Years Ending December 31,	Commitment Amount
	(In thousands)
2003	$ 1,468
2004	2,719
2005	2,719
2006	2,719
2007	2,719
Thereafter	7,216
	$19,560

Processing Commitment

In March 2001, the Company entered into a new gas processing agreement to expand available capacity for its gas production from the White River Dome coal bed methane project in the Piceance Basin. The plant commenced operations in October 2001. The Company is obligated to pay processing fees for certain variable expenses of the plant associated with the processed volumes and compression made available during the ten-year term of this agreement. Additionally, the fixed operating costs and capital recovery obligations to the plant contractor total approximately $220,000 per month over the term of this agreement.

Drilling Rig Obligation

To assure the availability of a drilling rig in conjunction with the continuing exploration program at the Deep Valley prospect in west Texas, the Company entered into a two-year commitment with a drilling contractor in 2001. The rig became available on March 1, 2002 after which a 90-day period was allowed under the terms of the agreement to mobilize the rig and commence the two-year drilling obligation. On May 29, 2002, the Company commenced drilling operations with this rig which was the start of the two-year obligation. Under the terms of this arrangement, the Company is obligated to ultimately pay a day rate of $20,100 per day during drilling operations, $16,700 per day for rig moves and a special standby fee of $6,000 per day during the initial 90-day commencement period. The special standby fees paid between March 1, 2002 and May 29, 2002 of $.5 million were expensed. The Company also expensed standby fees incurred when the rig was idle between drilling operations of $1.1 million in 2002.

Environmental Matters

Rocno Corporation, a wholly-owned subsidiary of the Company, is a party to a trust agreement in connection with the environmental clean-up plan for the Sheridan Superfund Site in Waller County, Texas. Rocno's share of the estimated cleanup costs was accrued in the consolidated financial statements at December 31, 2002. Based on the amount of remediation costs estimated for this site and the Company's *de minimis* contribution, if any, the Company believes that the outcome of this site restoration project will not have a material adverse effect on its financial position or results of operations.

(13) Quarterly Financial Data (Unaudited)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(In thousands, except per share amounts)				
Year ended December 31, 2002					
Revenues	$ 48,294	$63,975	$52,165	$71,211	$235,645
Gross profit (1)	32,600	44,668	35,467	51,594	164,329
Net (loss) income attributable to common Stock	(18,474)	4,755	(1,831)	7,373	(8,177)
Net (loss) income per common share (2)					
Basic	(.47)	.12	(.05)	.19	(.21)
Diluted	(.47)	.12	(.05)	.18	(.20)
Year ended December 31, 2001					
Revenues	$118,684	$95,386	$59,252	$53,002	$326,324
Gross profit (1)	90,609	62,460	45,155	37,008	235,232
Net income attributable to common Stock	37,466	26,234	5,770	33	69,503
Net income per common share (2)					
Basic	.97	.67	.15	—	1.78
Diluted	.93	.65	.14	—	1.73

(1) Gross Profit is computed as the excess of gas and oil sales and marketing, trading gathering and processing revenues over operating expenses. Operating expenses are those associated directly with gas and oil sales and marketing, gathering and processing revenues and include lease operations, gas and oil related taxes and cost of gas sold.

(2) The sum of the individual quarterly net income per share does not agree with year-to-date net income per share as each period's computation is based on the weighted average number of common shares outstanding during that period.

(14) Supplemental Information Related to Gas and Oil Activities

The following tables set forth certain historical costs and operating information related to the Company's gas and oil producing activities:

Capitalized Costs and Costs Incurred

	December 31,		
	2002	2001	2000
		(In thousands)	
Capitalized costs			
Proved gas and oil properties	$907,006	$780,300	$526,269
Unproved gas and oil properties	52,801	69,328	49,722
Total gas and oil properties	959,807	849,628	575,991
Less: Accumulated depreciation, depletion and Amortization	(290,983)	(213,297)	(160,738)
Net capitalized costs	$668,824	$636,331	$415,253

	United States	Canada	Total
		(In thousands)	
2002			
Costs incurred			
Proved property acquisition costs	$ 15,878	$ —	$ 15,878
Unproved property acquisition costs	7,601	1,414	9,015
Exploration costs	32,482	2,553	35,035
Development costs	85,319	9,248	94,567
Total	$141,280	$ 13,215	$154,495
2001			
Costs incurred			
Proved property acquisition costs	$ 3,649	$ 85,025	$ 88,674
Unproved property acquisition costs	16,496	14,132	30,628
Exploration costs	55,357	2,585	57,942
Development costs	138,815	24,395	163,210
Total	$214,317	$126,137	$340,454
2000			
Costs incurred			
Proved property acquisition costs	$ 17,111	$ —	$ 17,111
Unproved property acquisition costs	16,831	—	16,831
Exploration costs	18,362	—	18,362
Development costs	74,406	—	74,406
Total	$126,710	$ —	$126,710

Gas and Oil Reserve Information (Unaudited)

The following summarizes the policies used by the Company in preparing the accompanying gas and oil reserve disclosures, Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Gas and Oil Reserves and reconciliation of such standardized measure between years.

(14) Supplemental Information Related to Gas and Oil Activities (Continued)

Estimates of proved and proved developed reserves were prepared by the Company's petroleum engineering staff and reviewed by the independent petroleum consultants. Proved reserves are estimated quantities of natural gas, crude oil and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can be recovered through existing wells with existing equipment and operating methods. The Company's gas, oil and natural gas liquids reserves are located in the United States and Canada.

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows:

1. Estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on year end economic conditions.

2. The estimated future cash flows from proved reserves were determined based on year-end prices, except in those instances where fixed and determinable price escalations are included in existing contracts.

3. The future cash flows are reduced by estimated production costs including overhead costs attributable to producing activities and costs to develop and produce the proved reserves, all based on year end economic conditions and by the estimated effect of future income taxes based on the then-enacted tax law, the Company's tax basis in its proved gas and oil properties and the effect of net operating loss, investment tax credit and other carryforwards.

The standardized measure of discounted future net cash flows does not purport to present, nor should it be interpreted to present, the fair value of the Company's gas, oil and natural gas liquids reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

(14) Supplemental Information Related to Gas and Oil Activities (Continued)

Quantities of Gas, Oil and Natural Gas Liquids Reserves (Unaudited)

The following table presents estimates of the Company's net proved and proved developed natural gas, oil and natural gas liquids.

	Reserve Quantities					
	Gas (Mmcf)			Oil (Mbls)		
	United States	Canada	Total	United States	Canada	Total
Proved reserves:						
Estimated reserves at December 31, 1999	445,933	—	445,933	6,735	—	6,735
Revisions of previous estimates	50,852	—	50,852	(196)	—	(196)
Purchases of minerals in place	28,960	—	28,960	17	—	17
Extensions and discoveries	60,827	—	60,827	470	—	470
Sales of minerals in place	—	—	—	(137)	—	(137)
Production	(51,199)	—	(51,199)	(773)	—	(773)
Estimated reserves at December 31, 2000	535,373	—	535,373	6,116	—	6,116
Revisions of previous estimates	(47,647)	(7,058)	(54,705)	(578)	156	(422)
Purchases of minerals in place	3,000	58,809	61,809	—	1,194	1,194
Extensions and discoveries	164,561	14,920	179,481	835	137	972
Sales of minerals in place	(16,072)	(483)	(16,555)	(181)	(151)	(332)
Production	(57,163)	(6,661)	(63,824)	(723)	(158)	(881)
Estimated reserves at December 31, 2001	582,052	59,527	641,579	5,469	1,178	6,647
Revisions of previous estimates	8,304	2,609	10,913	580	318	898
Purchases of minerals in place	15,661	—	15,661	34	—	34
Extensions and discoveries	79,582	4,791	84,373	193	258	451
Sales of minerals in place	(6,322)	—	(6,322)	(1,162)	—	(1,162)
Production	(65,781)	(6,386)	(72,167)	(623)	(220)	(843)
Estimated reserves at December 31, 2002	613,496	60,541	674,037	4,491	1,534	6,025
Proved developed reserves:						
December 31, 1999	333,858	—	333,858	5,419	—	5,419
December 31, 2000	431,824	—	431,824	5,012	—	5,012
December 31, 2001	428,719	51,392	480,111	4,051	900	4,951
December 31, 2002	451,183	56,239	507,422	3,299	1,252	4,551

(14) Supplemental Information Related to Gas and Oil Activities (Continued)

	Reserve Quantities		
		Liquids (Mbls)	
	United States	Canada	Total
Proved reserves:			
Estimated reserves at December 31, 1999	6,266	—	6,266
Revisions of previous estimates	(115)	—	(115)
Purchases of minerals in place	—	—	—
Extensions and discoveries	—	—	—
Sales of minerals in place	—	—	—
Production	(1,074)	—	(1,074)
Estimated reserves at December 31, 2000	5,077	—	5,077
Revisions of previous estimates	529	(268)	261
Purchases of minerals in place	—	1,644	1,644
Extensions and discoveries	2,102	511	2,613
Sales of minerals in place	—	(18)	(18)
Production	(1,074)	(143)	(1,217)
Estimated reserves at December 31, 2001	6,634	1,726	8,360
Revisions of previous estimates	(956)	328	(628)
Purchases of minerals in place	—	—	—
Extensions and discoveries	186	119	305
Sales of minerals in place	—	—	—
Production	(1,189)	(193)	(1,382)
Estimated reserves at December 31, 2002	4,675	1,980	6,655
Proved developed reserves:			
December 31, 1999	5,979	—	5,979
December 31, 2000	5,077	—	5,077
December 31, 2001	5,577	1,439	7,016
December 31, 2002	4,002	1,823	5,825

(14) Supplemental Information Related to Gas and Oil Activities (Continued)

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Gas and Oil Reserves (Unaudited)

	December 31, 2002		
	United States	Canada	Total
		(In thousands)	
Future cash flows	$2,243,751	$ 326,417	$2,570,168
Future production costs	(732,739)	(66,898)	(799,637)
Future development costs	(175,085)	(11,278)	(186,363)
Future net cash flows before tax	1,335,927	248,241	1,584,168
Future income taxes	(367,271)	(84,435)	(451,706)
Future net cash flows after tax	968,656	163,806	1,132,462
Annual discount at 10%	(405,487)	(62,967)	(468,454)
Standardized measure of discounted future net cash flows	$ 563,169	$ 100,839	$ 664,008
Discounted future net cash flows before income taxes	$ 744,608	$ 138,745	$ 883,353

	December 31, 2001		
	United States	Canada	Total
		(In thousands)	
Future cash flows	$1,448,747	$ 188,317	$1,637,064
Future production costs	(530,791)	(57,248)	(588,039)
Future development costs	(164,226)	(5,525)	(169,751)
Future net cash flows before tax	753,730	125,544	879,274
Future income taxes	(89,389)	(30,538)	(119,927)
Future net cash flows after tax	664,341	95,006	759,347
Annual discount at 10%	(275,838)	(30,813)	(306,651)
Standardized measure of discounted future net cash flows	$ 388,503	$ 64,193	$ 452,696
Discounted future net cash flows before income taxes	$ 429,906	$ 71,382	$ 501,288

	December 31, 2000		
	United States	Canada	Total
		(In thousands)	
Future cash flows	$5,028,357	$ —	$5,028,357
Future production costs	(857,767)	—	(857,767)
Future development costs	(89,216)	—	(89,216)
Future net cash flows before tax	4,081,374	—	4,081,374
Future income taxes	(1,409,295)	—	(1,409,295)
Future net cash flows after tax	2,672,079	—	2,672,079
Annual discount at 10%	(1,196,324)		(1,196,324)
Standardized measure of discounted future net cash flows	$1,475,755	$ —	$1,475,755
Discounted future net cash flows before income taxes	$2,187,925	$ —	$2,187,925

(14) Supplemental Information Related to Gas and Oil Activities (Continued)

Changes in Standardized Measure of Discounted Future Net Cash Flows (Unaudited)

	Year Ended December 31, 2002		
	United States	Canada	Total
		(In thousands)	
Gas and oil sales, net of production costs (1)	$ (122,574)	$ (22,930)	$ (145,504)
Net changes in anticipated prices and production cost	265,587	60,103	325,690
Extensions and discoveries, less related costs	95,798	16,220	112,018
Changes in estimated future development costs	2,752	(4,565)	(1,813)
Previously estimated development costs incurred	37,124	2,282	39,406
Net change in income taxes	(140,036)	(30,717)	(170,753)
Purchase of minerals in place	16,970	—	16,970
Sales of minerals in place	(11,383)	—	(11,383)
Accretion of discount	42,990	7,138	50,128
Revision of quantity estimates	7,586	11,561	19,147
Changes in production rates and other	(20,148)	(2,446)	(22,594)
Change in Standardized Measure	$ 174,666	$ 36,646	$ 211,312

(1) Net of hedging revenue of $.2 million on production in the United States and a $.2 million hedging loss on Canadian production.

	Year Ended December 31, 2001		
	United States	Canada	Total
		(In thousands)	
Gas and oil sales, net of production costs (2)	$ (180,218)	$ (24,926)	$ (205,144)
Net changes in anticipated prices and production cost	(1,821,163)	(66,916)	(1,888,079)
Extensions and discoveries, less related costs	92,376	20,262	112,638
Changes in estimated future development costs	(868)	—	(868)
Previously estimated development costs incurred	36,691	7,693	44,384
Net change in income taxes	670,767	(7,188)	663,579
Purchase of minerals in place	3,500	153,017	156,517
Sales of minerals in place	(61,623)	(1,155)	(62,778)
Accretion of discount	218,793	—	218,793
Revision of quantity estimates	(34,549)	(12,706)	(47,255)
Changes in production rates and other	(10,957)	(3,889)	(14,846)
Change in Standardized Measure	$ (1,087,251)	$ 64,192	$ (1,023,059)

(2) Net of hedging revenue of $15.8 million on United States production.

(14) Supplemental Information Related to Gas and Oil Activities (Continued)

	Year Ended December 31, 2000		
	United States	Canada	Total
		(In thousands)	
Gas and oil sales, net of production costs	$ (169,375)	$ —	$ (169,375)
Net changes in anticipated prices and production cost	1,535,058	—	1,535,058
Extensions and discoveries, less related costs	251,410	—	251,410
Changes in estimated future development costs	8,831	—	8,831
Previously estimated development costs incurred	26,084	—	26,084
Net change in income taxes	(652,306)	—	(652,306)
Purchase of minerals in place	18,917	—	18,917
Sales of minerals in place	(679)	—	(679)
Accretion of discount	39,343	—	39,343
Revision of quantity estimates	198,625	—	198,625
Changes in production rates and other	(113,712)	—	(113,712)
Change in Standardized Measure	$1,142,196	$ —	$1,142,196

ITEM 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

On March 19, 2002, Arthur Andersen LLP ("Andersen") was dismissed as independent accountant for Tom Brown, Inc. (the "Company") effective upon completion of its audit of the Company's financial statements for the year ended December 31, 2001, and KPMG LLP ("KPMG") was appointed as the new independent accountant for the Company to replace Andersen for the year ending December 31, 2002. The decision to dismiss Andersen and to appoint KPMG was recommended by the Audit Committee of the Board of Directors and was approved by the Board of Directors at its meeting on March 19, 2002.

Andersen's reports on the Company's financial statements for the two fiscal years ended December 31, 2000 and December 31, 2001, did not contain an adverse opinion or disclaimer of opinion and were not qualified or modified as to uncertainty, audit scope or accounting principles.

During the Company's two most recent fiscal years and the period from January 1, 2002 through March 19, 2002, there were no disagreements between the Company and Andersen on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, which disagreements, if not resolved to the satisfaction of Andersen, would have caused it to make reference to the subject matter of the disagreements in connection with its report.

PART III

ITEM 10. ***Directors and Executive Officers of the Registrant***

Certain information regarding Directors of the Company will be included in the Company's definitive proxy statement to be filed with the Securities and Exchange Commission not later than 120 days after the end of the Company's fiscal year covered by this Form 10-K and such information is incorporated by reference to the Company's definitive proxy statement. Information concerning the Executive Officers of the Company appears under Item I of this Annual Report on Form 10-K.

ITEM 11. *Executive Compensation*

Certain information regarding compensation of executive officers of the Company will be included in the Company's definitive proxy statement to be filed with the Securities and Exchange Commission not later than 120 days after the end of the Company's fiscal year covered by this Form 10-K and such information is incorporated by reference to the Company's definitive proxy statement.

ITEM 12. ***Security Ownership of Certain Beneficial Owners and Management***

Certain information regarding security ownership of certain beneficial owners and management will be included in the Company's definitive proxy statement to be filed with the Securities and Exchange Commission not later than 120 days after the end of the Company's fiscal year covered by this Form 10-K and such information is incorporated by reference to the Company's definitive proxy statement.

Equity Compensation Plan Information

The following table provides information as of December 31, 2002 regarding the number of shares of Common Stock that may be issued under the Company's equity compensation plans.

Plan Category	Number of shares to be issued upon exercise of outstanding options, warrants and rights as of December 31, 2002	Weighted-average exercise price of outstanding options, warrants and rights as of December 31, 2002	Number of shares remaining available for future issuance under equity compensation plans as of December 31, 2002
Equity compensation plans approved by security holders			
1989 Plan (1)	336,216	$ 14.99	—
1999 Plan	1,197,513	$ 22.20	680,000
Equity compensation plans not approved by security holders			
1993 Plan (2)	2,778,960	$ 20.91	79,184
TOTAL	4,312,689	$ 20.81	759,184

(1) The 1989 Stock Option Plan expired on December 12, 1999.

(2) The 1993 Stock Option Plan was adopted by the Board in February 1993 as a broad-based plan with nonstatutory options being granted during its term to directors and officers as well as employees throughout the Company. The plan was administered by the Compensation Committee in the same manner as the plans which were approved by the Company's stockholders. The plan terminated on February 24, 2003 and all remaining shares reserved for future issuance at such time were forfeited back to the pool of authorized, but unissued, shares of the Company.

ITEM 13. *Certain Relationships and Related Transactions*

Certain information regarding transactions with management and other related parties will be included in the Company's definitive proxy statement to be filed with the Securities and Exchange Commission not later than 120 days after the end of the Company's fiscal year covered by this Form 10-K and such information is incorporated by reference to the Company's definitive proxy statement.

ITEM 14. *Controls and Procedures*

The Company's management, including the Chief Executive Officer and Chief Financial Officer, have conducted an evaluation of the effectiveness of disclosure controls and procedures pursuant to Exchange Act Rule 13a-14. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the disclosure controls and procedures are effective in ensuring that all material information required to be filed in this annual report has been made known to them in a timely fashion. There have been no significant changes in internal controls, or in factors that could significantly affect internal controls, subsequent to the date the Chief Executive Officer and Chief Financial Officer completed their evaluation.

PART IV

ITEM 15. ***Exhibits, Consolidated Financial Statement Schedules and Reports on Form 8-K***

(1) *See Index to Consolidated Financial Statements under Item 8 of this Annual Report on Form 10-K.*

(2) *None*

(3) *Exhibits:*

2.1	—	Purchase and Sale Agreement, dated June 8, 1999, between Union Oil Company of California and the Registrant. (Incorporated by reference to Exhibit 10.1 in the Registrant's Form 8-K Report dated July 19, 1999 and filed with the Securities and Exchange Commission on July 19, 1999)
2.2	—	Pre-Acquisition Agreement, dated December 13, 2000, between Stellarton Energy Corporation and the Registrant. (Incorporated by reference to Exhibit 2.2 in the Registrant's Form 10-K Report for the fiscal year ended December 31, 2000, and filed with the Securities and Exchange Commission on March 13, 2001)
3.1	—	Certificate of Incorporation, as amended, of the Registrant. (Incorporated by reference to Exhibit 3.1 in the Registrant's Form S-8 Report filed with the Securities and Exchange Commission on December 6, 2000)
3.2	—	Amended and Restated Bylaws, dated May 10, 2001. (Incorporated by reference to Exhibit 3.1 in the Registrant's Form 10-Q, for the quarterly period ended March 31, 2001, and filed with the Securities and Exchange Commission on May 14, 2001)
4.1	—	First Amended and Restated Rights Agreement dated March 1, 2001 between the Registrant and EquiServe Trust Company, N.A. (Incorporated by reference to Exhibit 4.2 in the Registrant's Form 10-K Report for the fiscal year ended December 31, 2000, and filed with the Securities and Exchange Commission on March 13, 2001)
10.1	—	Stock Ownership and Registration Rights Agreement dated June 29, 1999 between Union Oil Company of California and the Registrant. (Incorporated by reference to Exhibit 10.2 in the Registrant's Form 8-K Report dated July 19, 1999, and filed with the Securities and Exchange Commission on July 19, 1999)
10.2	—	U.S. Revolving Credit Agreement dated March 20, 2001. (Incorporated by reference to Exhibit 10.2 in the Registrant's Form 10-Q Report for the quarterly period ended March 31, 2001 and filed with the Securities and Exchange Commission on May 14, 2001)
10.3	—	Canadian Revolving Credit Agreement dated March 20, 2001. (Incorporated by reference to Exhibit 10.3 in the Registrant's Form 10-Q Report for the quarterly period ended March 31, 2001 and filed with the Securities and Exchange Commission on May 14, 2001)
10.4	—	Canadian Term Credit Agreement dated March 20, 2001. (Incorporated by reference to Exhibit 10.4 in the Registrant's Form 10-Q Report for the quarterly period ended March 31, 2001 and filed with the Securities and Exchange Commission on May 14, 2001)

10.5 — Credit Agreement dated June 30, 2000, among the Registrant, The Chase Manhattan Bank and the other lenders parties thereto. (Incorporated by reference to Exhibit 10.1 in the Registrant's Form 10-Q Report for the quarterly period ended June 30, 2000, and filed with the Securities and Exchange Commission on August 14, 2000)

10.6 — Credit Agreement, dated as of April 17, 1998, among the Registrant, The Chase Manhattan Bank and the other lenders parties thereto. (Incorporated by reference to Exhibit 10.1 in the Registrant's Form 10-Q for the quarterly period ended March 31, 1998, and filed with the Securities and Exchange Commission on May 14, 1998)

10.7 — First Amendment, dated October 19, 1998, to the Credit Agreement, dated April 17, 1998. (Incorporated by referenceto Exhibit 10.1 in the Registrant's Form 10-Q Report for the quarterly period ended September 30, 1998, and filed with the Securities and Exchange Commission on November 13, 1998)

10.8 — Second Amendment and Waiver, dated March 15, 1999, to the Credit Agreement, dated April 17, 1998. (Incorporated by reference to Exhibit 10.7 in the Registrant's Form 10-K Report for the fiscal year ended December 31, 1998 and filed with the Securities and Exchange Commission on March 19, 1999)

10.9 — Third Amendment, dated June 25, 1999, to the Credit Agreement, dated April 17, 1998. (Incorporated by reference to Exhibit 10.1 in the Registrant's Form 10-Q Report for the quarterly period ended June 30, 1999, and filed with the Securities and Exchange Commission on August 13, 1999)

Executive Compensation Plans and Arrangements (Exhibits 10.10 through 10.24):

10.10 — Second Amendment and Restated Employment Agreement dated January 1, 1997, between the Registrant and Donald L. Evans. (Incorporated by reference to Exhibit 10.15 in the Registrant's Form 10-K Report for the fiscal year ended December 31, 1996, and filed with the Securities and Exchange Commission on March 27, 1997)

10.11 — First Amendment to Employment Agreement dated as of July 1, 1998, between the Registrant and Donald L. Evans. (Incorporated by reference to Exhibit 10.3 in the Registrant's Form 10-Q Report for the quarterly period ended June 30, 1998, and filed with the Securities and Exchange Commission on August 10, 1998)

10.12 — Employment Agreement dated May 3, 1999 between the Registrant and James D. Lightner. (Incorporated by reference to Exhibit 10.3 in the Registrant's Form 8-K Report dated July 19, 1999, and filed with the Securities and Exchange Commission on July 19, 1999)

10.13* — Employment Agreement dated January 1, 2003 between the Registrant and James D. Lightner.

10.14 — The Registrant's Severance Plan dated as of July 1, 1998. (Incorporated by reference to Exhibit 10.2 in the Registrant's Form 10-Q Report for the quarterly period ended June 30, 1998, and filed with the Securities and Exchange Commission on August 12, 1998)

10.15 — First Amendment to Tom Brown, Inc. Severance Plan dated May 10, 2001. (Incorporated by reference to Exhibit 10.5 in the Registrant's Form 10-Q Report for the quarterly period ended March 31, 2001 and filed with the Securities and Exchange Commission on May 14, 2001)

10.16	—	Severance Agreement dated as of July 1, 1998, together with a schedule identifying officers of the Registrant who are parties thereto and the multiple of earnings payable to each officer upon termination resulting from certain change in control events. (Incorporated by reference to Exhibit 10.1 in the Registrant's Form 10-Q Report for the quarterly period ended June 30, 1998, and filed with the Securities and Exchange Commission on August 12, 1998)
10.17	—	First Amendment to Severance Agreement dated May 10, 2001. (Incorporated by reference to Exhibit 10.8 in the Registrant's Form 10-Q Report for the quarterly period ended March 31, 2001 and filed with the Securities and Exchange Commission on May 14, 2001)
10.18	—	Amended Schedule to Severance Agreement identifying officers and executives of the Registrant who are parties thereto and the multiple of earnings payable to each officer or executive upon termination resulting from certain change in control events. (Incorporated by reference to Exhibit 10.17 in the Registrant's Form 10-K Report for the fiscal year ended December 31, 2001, and Filed with the Securities and Exchange Commission on March 19, 2002)
10.19	—	Deferred Compensation Plan dated March 1, 2001. (Incorporated by reference to Exhibit 10.22 in the Registrant's Form 10-K Report for the fiscal year ended December 31, 2000, and filed with the Securities and Exchange Commission on March 13, 2001)
10.20	—	1999 Long-Term Incentive Plan effective as of February 17, 1999. (Incorporated by reference to Exhibit 10.11 in the Registrant's Form 10-K Report for the fiscal year ended December 31, 1999, and filed with the Securities and Exchange Commission on March 22, 2000)
10.21	—	Amendment to Tom Brown, Inc. 1999 Long-Term Incentive Plan dated May 10, 2001. (Incorporated by reference to Exhibit 10.6 in the Registrant's Form 10-Q Report for the quarterly period ended March 31, 2001 and filed with the Securities and Exchange Commission on May 14, 2001)
10.22	—	Amended and Restated 1993 Stock Option Plan. (Incorporated by reference to Exhibit 10.1 in the Registrant's Form 10-Q Report for the quarterly period ended March 31, 2001 and filed with the Securities and Exchange Commission on May 14, 2001)
10.23	—	Amendment to Tom Brown, Inc. Amended and Restated 1993 Stock Option Plan dated May 10, 2001. (Incorporated by reference to Exhibit 10.7 in the Registrant's Form 10-Q Report for the quarterly period ended March 31, 2001 and filed with the Securities and Exchange Commission on May 14, 2001)
10.24	—	1989 Stock Option Plan. (Incorporated by reference to Exhibit 10.17 in the Registrant's Form S-1 Registration Statement dated February 14, 1990, and filed with the Securities and Exchange Commission on February 13, 1990)
21.1*	—	Subsidiaries of the Registrant
23.1*	—	Consent of KPMG LLP
23.2*	—	Information Regarding Consent of Arthur Andersen LLP
23.3*	—	Consent of Ryder Scott Company

99.1	—	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.2	—	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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* Filed herewith

(4) *Reports on Form 8-K:*

Form 8-K Item 5.	Press release dated February 20, 2003, entitled "Tom Brown, Inc. Reports Fourth Quarter and Full Year 2002 Earnings and Operating Results; Provides 2003 Guidance" filed on February 25, 2003.
Form 8-K Item 5.	Press release dated February 20, 2003, entitled "Tom Brown, Inc. Announces Year-End Reserves" filed on February 25, 2003.

SIGNATURES

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

TOM BROWN, INC.

By /s/ JAMES D. LIGHTNER

James D. Lightner
Chairman, Chief Executive Officer and President

Date: March 25, 2003

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

Signature	Title	Date
/s/ JAMES D. LIGHTNER James D. Lightner	Chairman, Chief Executive Officer and President	March 25, 2003
/s/ DANIEL G. BLANCHARD Daniel G. Blanchard	Executive Vice President, Chief Financial Officer and Treasurer	March 25, 2003
/s/ RICHARD L. SATRE Richard L. Satre	Controller	March 25, 2003
/s/ THOMAS C. BROWN Thomas C. Brown	Director	March 25, 2003
/s/ DAVID M. CARMICHAEL David M. Carmichael	Director	March 25, 2003
/s/ HENRY GROPPE Henry Groppe	Director	March 25, 2003
/s/ EDWARD S. LEBARON, JR. Edward S. LeBaron, Jr.	Director	March 25, 2003
/s/ ROBERT H. WHILDEN, JR. Robert H. Whilden, Jr.	Director	March 25, 2003
/s/ WAYNE W. MURDY Wayne W. Murdy	Director	March 25, 2003
/s/ JAMES B. WALLACE James B. Wallace	Director	March 25, 2003
/s/ JOHN C. LINEHAN John C. Linehan	Director	March 25, 2003

TOM BROWN, INC.

CERTIFICATIONS PURSUANT TO
SECTION 302 OF
THE SARBANES-OXLEY ACT OF 2002

CERTIFICATION

I, Daniel G. Blanchard, certify that:

1. I have reviewed this annual report on Form 10-K of Tom Brown, Inc.;

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

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

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

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

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 18, 2003

/s/ Daniel G. Blanchard
Executive Vice President, Chief Financial Officer and Treasurer

CERTIFICATION

I, James D. Lightner, certify that:

1. I have reviewed this annual report on Form 10-K of Tom Brown, Inc.;

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

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

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

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

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 18, 2003

/s/ James D. Lightner
Chairman, Chief Executive Officer and President

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Corporate Information

ANNUAL MEETING

The 2003 annual meeting of Tom Brown, Inc. shareholders will be held May 8, 2003, at 9:00 a.m. Central Time, at the Petroleum Club in Midland, Texas. The usual notice and proxy statements will be mailed to all registered shareholders in advance of the meeting.

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COMMON STOCK

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TRANSFER AGENT

EquiServe Trust Company, N.A.
P.O. Box 9187
Canton, MA 02021
(816) 843-4299
Website: www.equiserve.com

Communication concerning the transfer of shares, lost certificates, duplicate mailings or change of address should be directed to the transfer agent.

LEGAL COUNSEL

Vinson & Elkins, L.L.P.
Houston, Texas

AUDITORS

KPMG LLP
Denver, Colorado

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