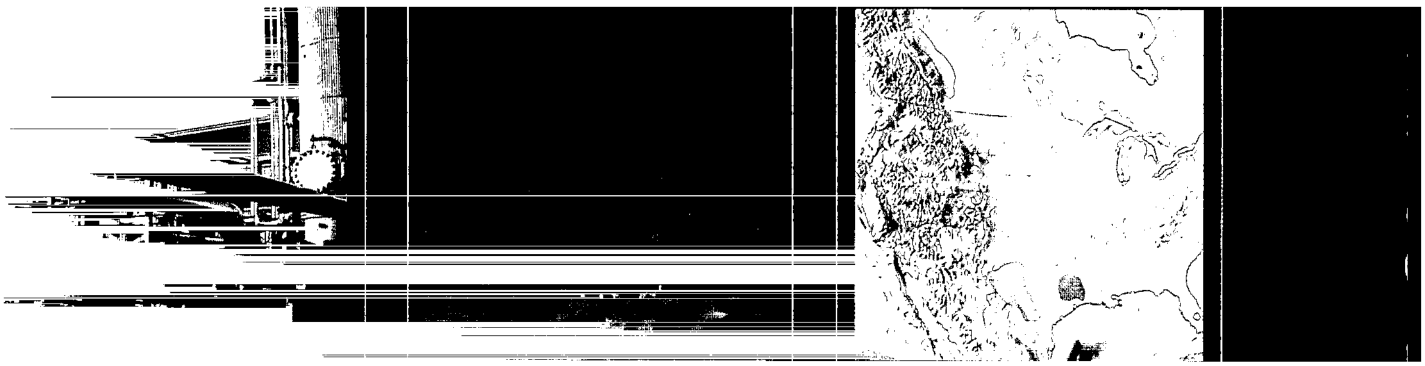
TOM BROWN, INC.



BALANCE

ANNUAL REPORT 2003

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 in the gas-prone basins of North America primarily in the Rocky Mountains (Wind River and Green River basins of Wyoming, the Piceance basin of Colorado, the Paradox basin of Colorado and Utah, and the Western Canadian Sedimentary basin) and its Southern area (the Permian basin of west Texas and southeastern New Mexico and the East Texas basin). The Company maintains a dominant land position in its core operating areas with over 2.2 million net acres, 84% of which are undeveloped.

At year-end 2003, the Company's proved reserves totaled 1,137.3 billion cubic feet equivalent (Bcfe). The year-end 2003 proved reserves are 92% natural gas and 64% of the reserves are from fields located in the Rockies. Net daily production in 2003 averaged 263.8 million cubic feet equivalent per day (Mmcfepd), a 13% increase over 2002. Tom Brown has achieved five year compound annual growth in production and proved reserves of 18% and 23%, respectively.

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

CONTENTS

Geographic and geologic balance

Tom Brown has consistently maintained a focused strategy of exploration for, and the acquisition and development of natural gas in the onshore North American natural gas-prone basins of the Rocky Mountain regions of the U.S. and Canada and the Permian and East Texas basins. In 2003, the Company balanced its asset mix between the Rocky Mountain region and its Southern area with the acquisition of Matador Petroleum Corporation.

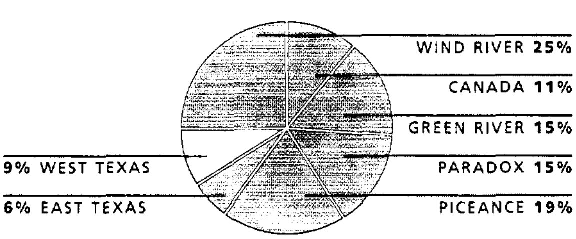
The Company closed the $388 million (including transaction-related costs) acquisition of Matador on June 27, 2003. The Matador acquisition increased the Company's concentration of assets within two of its core areas—the East Texas and Permian basins. The acquisition added 269 Bcfe to Tom Brown's proved reserves, maintained our focus on natural gas, added to our low risk inventory of drilling locations and balanced our natural gas price exposure between the Rockies and Texas.

Natural gas produced in Texas generally sells for a higher realized price than natural gas produced in the Rockies. With an increased concentration of reserves in Texas, we have improved our overall natural gas price realization and we expect to reduce our price volatility to the New York Mercantile Exchange (NYMEX) price. The Company's 2003 natural gas price realization before hedges, which included the operating results from the properties acquired from Matador for July 2003 forward, averaged 82% of NYMEX as compared to a pre-hedge price that averaged 68% of NYMEX for 2002.

Of equal importance to improved natural gas pricing, the Matador properties have significant potential for increased production and reserves. Tom Brown has the opportunity, with our team of dedicated technical staff, to create significant value on the acquired properties.

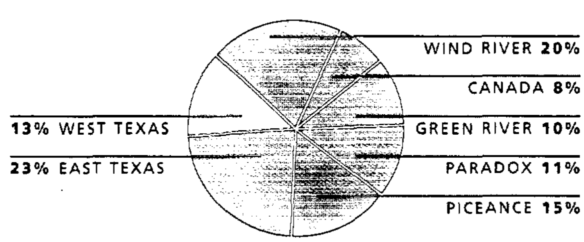
2002 PROVED RESERVES (750.1 Bcfe)

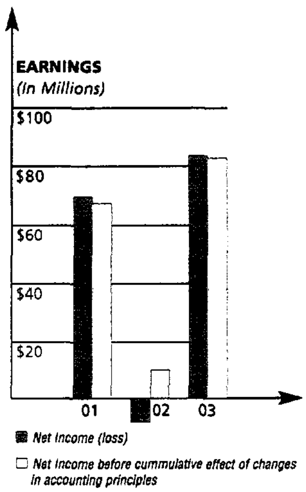
85% ROCKIES

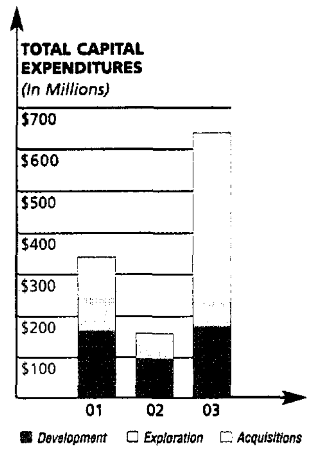


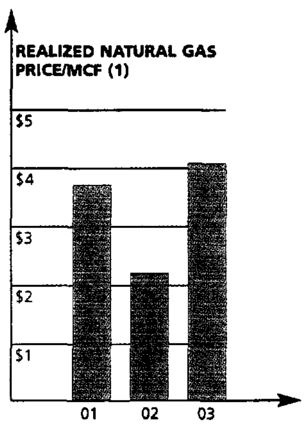
2003 PROVED RESERVES (1,137.3 Bcfe)

64% ROCKIES

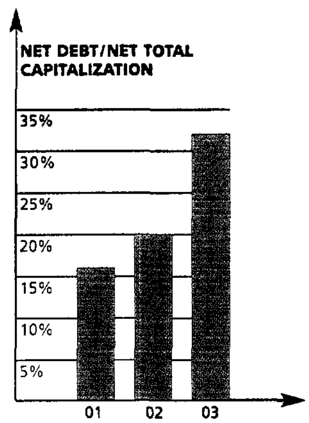






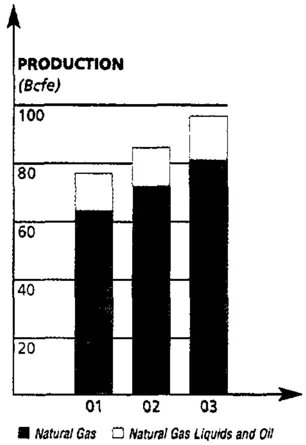


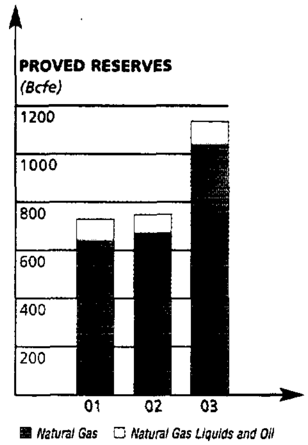
(1) Includes the effect of hedging

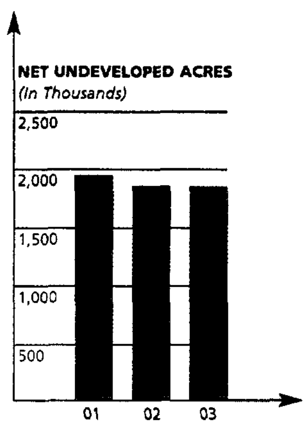


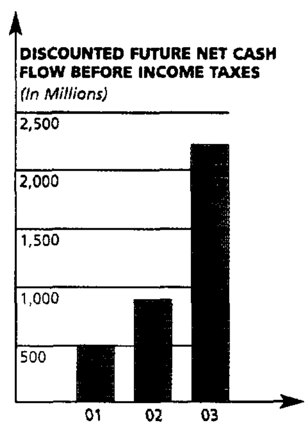
THREE-YEAR FINANCIAL SUMMARY

(Thousands except per share amounts)	2001	2002	2003
Total revenues	$ 449,100	$ 289,268	$ 467,607
Income before cumulative effect of change in accounting principles	$ 67,477	$ 9,926	$ 83,666
Net income (loss)	$ 69,503	$ (8,177)	$ 82,737
Per share, diluted	$ 1.73	$ (0.20)	$ 1.95
Weighted average common shares outstanding, diluted	40,227	40,327	42,365
Total exploration, development and acquisition capital expenditures	$ 340,454	$ 154,495	$ 640,133
Total assets	$ 844,975	$ 850,952	$1,568,434
Working capital	$ 11,278	$ (8,887)	$ 18,564
Property and equipment, net	$ 738,526	$ 776,485	$1,304,567
Total debt	$ 120,570	$ 133,172	$ 394,080
Stockholders' equity	$ 575,228	$ 563,618	$ 812,952









Average wellhead natural gas price used in determining the present value: 2001 - $2.20, 2002 - $3.33, 2003 - $5.38

OPERATIONS

	2001	*2002*	*2003*
YEAR-END RESERVES:			
Natural gas *(Mmcf)*	641,579	674,037	1,041,828
Oil and natural gas liquids *(MBbl)*	15,007	12,680	15,908
Total equivalent *(Mmcfe)*	731,621	750,116	1,137,273
Discounted future net cash flow before income taxes *(in thousands)*	$ 501,288	$ 883,352	$ 2,221,130
PRODUCTION:			
Natural gas *(Mmcf)*	63,824	72,167	81,258
Natural gas liquids *(MBbl)*	1,217	1,382	1,445
Oil *(MBbl)*	881	843	1,058
Total equivalent *(Mmcfe)*	76,412	85,517	96,275
AVERAGE SALES PRICE:			
Natural gas *($/Mcf)*	$ 3.71	$ 2.19	$ 4.07
Natural gas liquids *($/Bbl)*	14.07	12.05	18.38
Oil *($/Bbl)*	23.09	23.41	29.05
Total equivalent *($/Mcfe)*	3.59	2.27	4.03
UNDEVELOPED ACREAGE *(in thousands of acres)*:			
Gross	2,892	2,710	2,695
Net	1,942	1,852	1,849

We have a very simple and straightforward strategy.

LETTER TO SHAREHOLDERS

What a difference a year makes! Through the combined efforts of all Tom Brown employees, the Company achieved records in earnings, discretionary cash flow, annual production and reserve growth in 2003, while greatly improving our position to generate future growth and value. These strong results followed a very difficult 2002 during which a high basis differential "blow-out" resulted in Rockies gas prices averaging under $2.00 per Mcf which significantly reduced Company revenues. The Rockies basis differential has improved significantly and we don't expect it to widen for the next several years thanks to new major pipeline projects and slowing growth in Rockies production. We are confident that this region will continue to be important to growing our Company's and the country's natural gas supplies. During the last two decades, the significant gas producing areas of the Mid-Continent and the Southwest have lost 25% to 30% of their productive capability while the U.S. Rockies has gained over 160%! Our breadth of Rockies opportunities, supported by 1.3 million net long-term acres strategically located across four major gas-producing basins, uniquely positions Tom Brown for future growth. Our capital and people commitments remain strong and we are consistently highgrading and adding to our holdings. However, operating on federal lands that comprise much of the Rockies remains a significant challenge, primarily due to numerous litigious anti-development groups that are bent on shutting down reasonable regulated access to America's clean-burning natural gas resources. Every day private and state owned lands are being safely developed by our industry, strictly adhering to all rules and regulations, while huge resources of adjacent federally owned natural gas go undeveloped. The unfortunate result of these illogical and punitive anti-development efforts is lower gas supply. Lower natural gas supply is one of the causes of the higher energy prices now facing almost every business and consumer in America. Less natural gas also means that the nation burns more coal. Emissions from natural gas-fired electrical power plants are approximately 90% cleaner than emissions from the nation's coal-fired power plants! For the good of our country and our environment you can and should get involved in this debate.

Diversity is healthy in any portfolio. We set out five years ago to diversify the Company's holdings out of the Wind River Basin in Wyoming so that our shareholders would benefit from exposure to different play types, different regulatory environments and better gas price indexes. Much progress has been made in these five years. In June 2003, we closed the Matador Petroleum Corporation acquisition, adding 269 Bcfe of reserves, 165,500 net acres of highly prospective and accessible leasehold and a team of talented and highly motivated people in our new Dallas Division. This strategic acquisition significantly strengthened our position in the prolific gas provinces of the East Texas and Permian basins where future opportunities and potential are very promising.

We have a very simple and straightforward strategy. We believe that the significant natural gas plays of the future in North America will come from the discovery and development of large scale "unconventional resource-type" plays. Our primary goal is to identify and position ourselves in the heart of these plays. The Company's 2.2 million net acres are situated in prime territory for many of these emerging plays and our Divisions are actively putting together large new projects. We have the right people, technology and organizational structure to make this happen and I am excited by the opportunities in each of our Divisions.

Our fully-staffed and motivated technical teams possessing decades of "area specific" regional expertise are a very potent force. It is truly inspiring to watch our Divisions meet the challenge of executing extremely active drilling programs while continuing to cut costs and generate new opportunities for the future. We are very efficient at exploiting our existing fields, which is a tremendous proven method to grow shareholder value. However, the challenge that E&P companies face today is one of replenishing depleting drilling inventories. New exploitation opportunities are really only replenished from acquisition and exploration success. The solution is simple in concept but difficult in application. The acquisition environment gets more competitive every day and there are still far too many buyers and too few sellers. Many companies have given up on exploration over the last decade. Last year, our industry drilled less than one third of the wildcats that were drilled during the depths of the industry crash in 1986! TBI's consistent commitment to exploration in every one of our core areas has begun to reap rewards. Exploratory successes at Deep Valley in the Midland Division, Fuller/Deadman, Frenchie Draw and South Parachute in the Denver Division, and numerous other projects that are in different stages of maturity in every one of our Divisions, are providing us with new fields to develop.

While the industry is widely perceived to be opportunity deficient, TBI's current drilling inventory has surpassed 3,200 lower risk drilling opportunities including PUD and probable locations. At last year's drilling activity level, this represents a 15-year inventory! Our goal is to make significant progress over the next 18 months towards testing the economic viability of many of these areas in order to prove up these reserves in a timely fashion.

While we remain in a volatile industry, make no mistake that there has been a fundamental shift in the nation's energy supply picture. Demand for energy is growing, oil and gas supplies have been dropping and there are no easy short-term solutions. As rapidly developing economies across the globe relentlessly compete for energy, the value of possessing a unique and growing set of long-term, clean-burning domestic natural gas assets will continue to be recognized and appreciated. As always, we remain committed to creating long-term shareholder value and believe we are ideally positioned to do so. On behalf of our Board of Directors, officers and employees, I thank you for your continued trust and support.

JAMES D. LIGHTNER
Chairman, Chief Executive Officer and President

Supply and demand balance

Natural gas price volatility over the last several years is a very visible indicator of a tight supply-demand balance. The Henry Hub spot natural gas price averaged $5.48 per Mmbtu in 2003 and averaged $4.27 per Mmbtu over the three-year period from 2001 to 2003. During that time, spot prices have swung from below $1.75 per Mmbtu in late 2001 to over $10 per Mmbtu both in early 2001 and 2003. This swing in prices reflects the tenuous balance between supply and demand.

Both natural gas supply and demand are impacted by numerous factors. Natural gas supplies are influenced by the level of drilling activity, Canadian imports, liquefied natural gas (LNG) shipments and the change in storage levels year to year. The level of drilling activity has historically mirrored commodity prices. In 2003, with the higher natural gas prices, the natural gas rig count averaged 868, an increase of 26% over 2002. Generally, higher drilling activity brings on new production, but with a time lag.

Natural gas consumption is heavily impacted by weather and the nation's economy. Residential demand can swing significantly from year to year depending on the amount of cold weather in the highly populated natural gas consuming areas of our country. Hot weather in the summer time and the resulting air conditioning load can drastically increase the amount of natural gas demand for electricity generation. Additionally, industrial demand can change due to fuel switching to other fuel sources and the general economic climate.

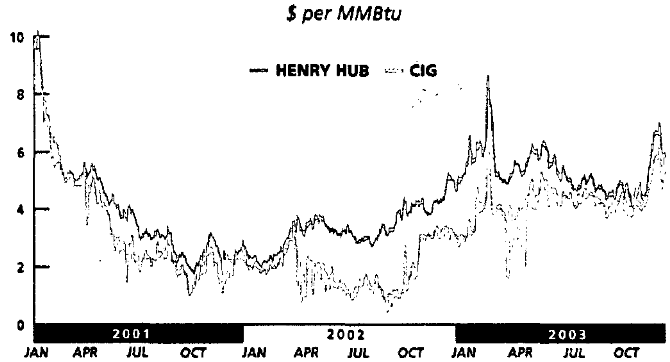
In 2003, despite more wells being drilled, the country's natural gas production fell and Canadian imports dropped. Additionally, residential demand increased with colder winter weather and storage had to be filled from historically low levels. All of these factors combined to cause the Henry Hub natural gas price to average $5.39 per Mmbtu in 2003.

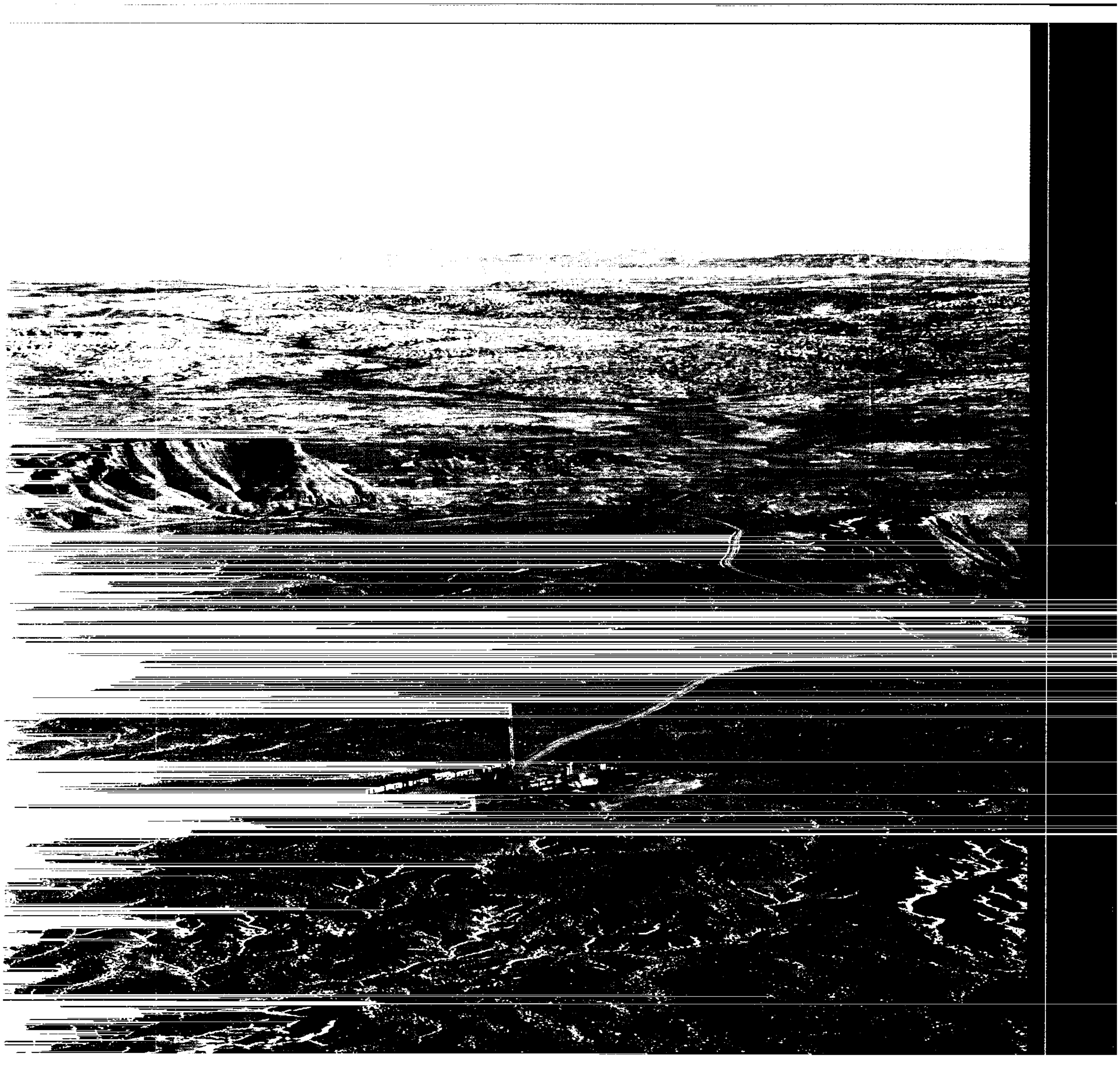
Northern Rockies Natural Gas Prices

Rockies natural gas in 2002 traded at a significant discount to NYMEX gas price. The Rockies price has been impacted by rising production within the region combined with limited local demand and insufficient pipeline takeaway capacity. In May 2003, the Kern River pipeline doubled its capacity to 1.7 Bcf per day which caused the differential to contract significantly. The Colorado Interstate Gas (CIG) gas traded at 75% of NYMEX in 2003 as compared to only 61% in 2002. For the second half of 2003 CIG traded at 88% of NYMEX, with the impact of the fully-functional Kern River pipeline.

NATURAL GAS PRICE

$ per MMBtu





BALANCE – We can develop our nation's energy resources and protect the environment – it's NOT one or the other.

A reliable and affordable supply of energy is critical to the well-being of our country. Domestic natural gas is vital to a diverse and well-balanced U.S. energy portfolio. Natural gas provides about a quarter of our country's energy needs and is easily the cleanest of our fossil fuels. Its production and use is critical to protecting the quality of our nation's environment.

Tom Brown recognizes the importance that clean-burning natural gas plays in providing energy for our country. We consider minimizing the impact of our operations on the environment to be a crucial part of how we conduct our business. We work closely with federal and state agencies and private land surface owners, following the stringent regulations which are placed on our exploration and production activities. Our employees are active in the communities in which we drill and are very committed to protecting the land in these communities. The impact of our activities is minimal and temportary. In most of our fields, drilling and completing a well takes 45-60 days. Upon completion there is limited evidence of our activity.

We are proud to be doing our part in providing our nation with a growing supply of clean-burning domestic energy. Unfortunately, our efforts and the efforts of our industry peers are often hampered by groups which oppose any development. This interference only endangers the stability of our domestic energy supply and increases the cost to consumers. We encourage the American public to recognize the importance that American natural gas plays in protecting our nation's jobs, economy, national security, and especially the environment.

CANADA	2001	2002	2003
roduction *(Mmcfepd)*	23.2	24.3	24.1
Total Gross Acreage *(in thousands)*	518	540	531
Total Net Acreage *(in thousands)*	350	359	343
&P Capital Spending *($s in MM)*	$30.8	$13.4	$31.2
ease Operating Expense *(per Mcfe)*	$0.62	$0.55	$0.70

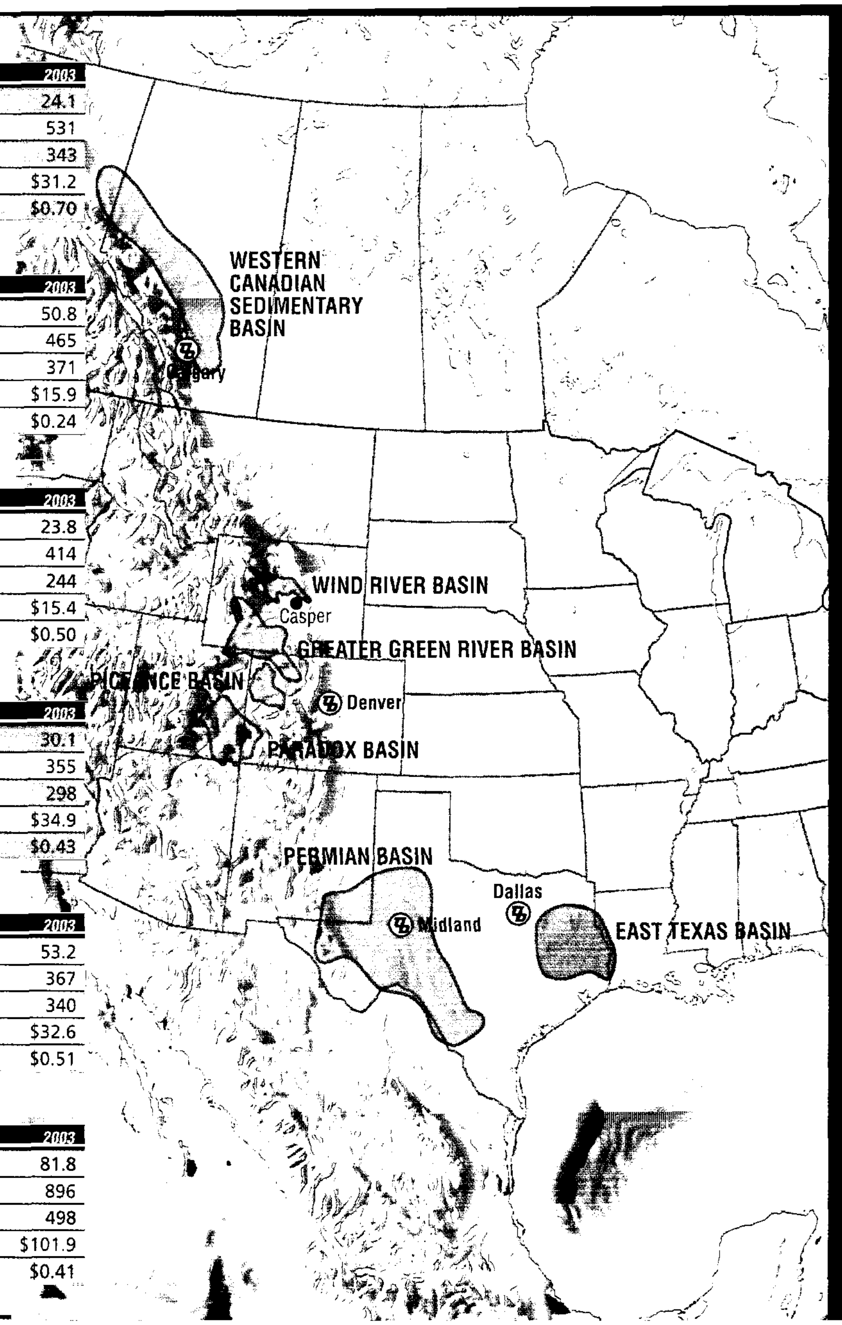
WIND RIVER BASIN	2001	2002	2003
roduction *(Mmcfepd)*	49.2	59.8	50.8
Total Gross Acreage *(in thousands)*	582	429	465
Total Net Acreage *(in thousands)*	412	344	371
&P Capital Spending *($s in MM)*	$61.2	$26.3	$15.9
ease Operating Expense *(per Mcfe)*	$0.17	$0.16	$0.24

REATER GREEN RIVER BASIN	2001	2002	2003
roduction *(Mmcfepd)*	25.2	22.0	23.8
Total Gross Acreage *(in thousands)*	505	469	414
Total Net Acreage *(in thousands)*	285	275	244
&P Capital Spending *($s in MM)*	$15.0	$8.2	$15.4
ease Operating Expense *(per Mcfe)*	$0.39	$0.49	$0.50

ICEANCE BASIN	2001	2002	2003
roduction *(Mmcfepd)*	23.8	32.9	30.1
Total Gross Acreage *(in thousands)*	403	362	355
Total Net Acreage *(in thousands)*	335	304	298
&P Capital Spending *($s in MM)*	$43.7	$26.0	$34.9
ease Operating Expense *(per Mcfe)*	$0.39	$0.36	$0.43

ARADOX BASIN	2001	2002	2003
roduction *(Mmcfepd)*	39.7	44.7	53.2
Total Gross Acreage *(in thousands)*	345	362	367
Total Net Acreage *(in thousands)*	322	341	340
&P Capital Spending *($s in MM)*	$20.9	$14.4	$32.6
ease Operating Expense *(per Mcfe)*	$0.64	$0.62	$0.51

SOUTHERN AREA	2001	2002	2003
roduction *(Mmcfepd)*	44.6	49.2	81.8
Total Gross Acreage *(in thousands)*	614	640	896
Total Net Acreage *(in thousands)*	325	356	498
&P Capital Spending *($s in MM)*	$58.0	$49.8	$101.9
ease Operating Expense *(per Mcfe)*	$0.35	$0.28	$0.41



Operations Overview

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 square miles.

TBI's Wind River basin (WRB) operations represent 20% of the Company's year-end 2003 proved reserves and 19% of its 2003 production. WRB operations are primarily conducted in the Pavillion, Muddy Ridge, Frenchie Draw, Sand Mesa and Fuller Reservoir/Deadman Hill fields. The Pavillion, Sand Mesa and Muddy Ridge fields are located on the Wind River Indian Reservation. There has been no drilling activity on the Wind River Indian Reservation since mid-year 2002 due to finalization of certain contractual issues with the Northern Arapaho and Eastern Shoshone tribes. The Fuller Reservoir Unit/Deadman Hill Unit is a new area for TBI and is located six miles east of the Indian Reservation.

In 2003, the Company drilled 17 gross wells in the WRB, of which 15 were successfully completed and two were waiting on completion or being evaluated at year-end. Eleven of the successful wells were in the Frenchie Draw field. In the Fuller/Deadman Hill area, the Company successfully drilled and completed two wildcats to the Fort Union interval: the Blazing Saddles (TBI 80% working interest) and the Lili 33-24 (TBI 79.1% working interest). These successful wells have created a significant area of further potential drilling for TBI. The Company has commenced an active development drilling program in this area targeting the Fort Union formation.

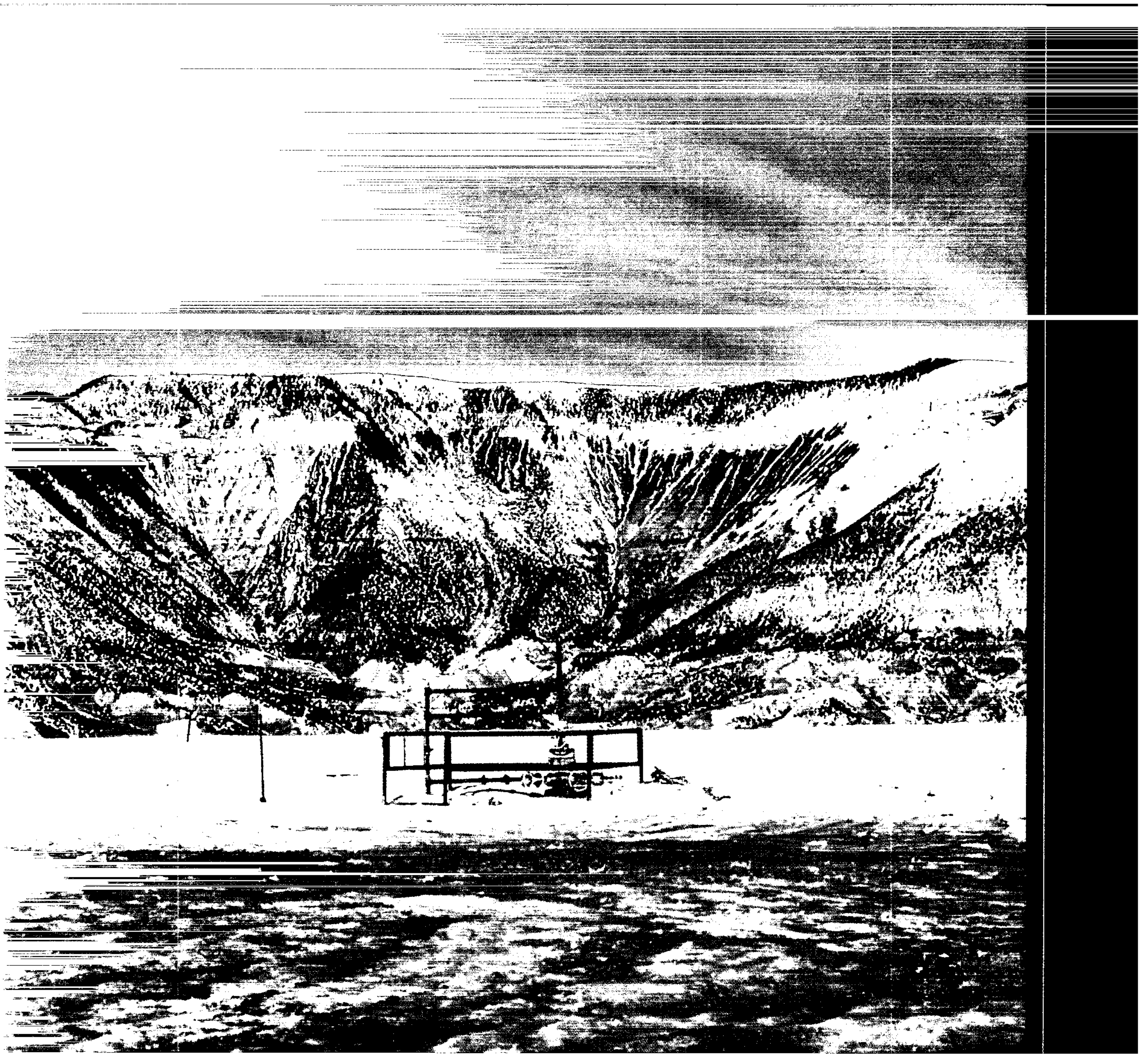
The Company's WRB properties produced an average of 50.8 Mmcfepd net for 2003, compared to 59.8 Mmcfepd net in 2002. This production decline was due to reduced drilling activity in the basin over the past 18 months.

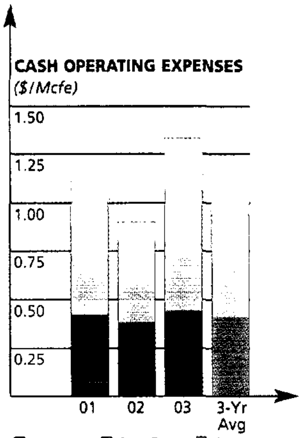
Greater Green River Basin

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 accounts for 10% of TBI's year-end 2003 proved reserves and 9% of the 2003 production. In 2003, the Company drilled or participated in 16 gross wells in the GGRB, of which 13 were successful. Of note, the CEPO Lewis 22-18 (TBI 30% working interest) had an initial production rate of 6.5 Mmcfepd and the Company is currently drilling a look-alike wildcat—the West Slope 33-32 (TBI 50% working interest).

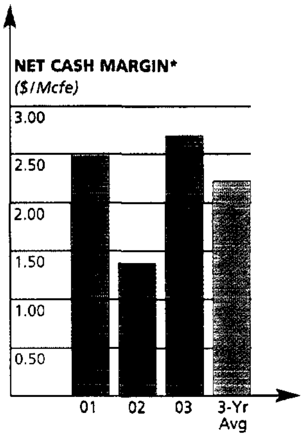
TBI produced an average of 23.8 Mmcfepd in 2003 from the GGRB compared to 22.0 Mmcfepd net in 2002. The increased production is a result of development activities at the Company's Hay Reservoir Unit and exploratory success at the CEPO Lewis 22-18.

The Company controls over 244,000 net undeveloped acres in the GGRB, and continues to explore for large unconventional basin-centered and coal bed methane gas accumulations.

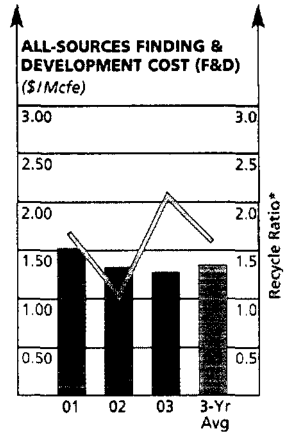




■ Production □ Prod. Taxes □ G&A
* Interest exp. and other
(1) General and administrative expense for 2001 includes the impact of additional compensation expense on chairman's retirement.



*Oil & Gas sales less: production expense, production taxes, general and adminstrative expense, and interest expense.



*Recycle ratio=Net Cash Margin/F&D Cost

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, on the east by the White River Uplift and on the west by the Douglas Creek Arch. The Piceance basin accounts for 15% of TBI's year-end 2003 proved reserves and 11% of the 2003 production.

For the year ended December 31, 2003, the Company drilled or participated in 36 gross wells and three were drilling at year-end. This drilling occurred principally in the Parachute, Grand Valley and White River Dome areas. The Company's 2003 drilling program in the Parachute/South Parachute area totaled 11 wells (TBI 70% average working interest), achieving a 100% success rate. The wells from this drilling program had an average initial production rate of 1.35 Mmcfepd from the Williams Fork formation. Due to an extensive field study and strong results this year in cost containment and completion efficiency, the Company has identified a significant inventory of future drilling locations. TBI is currently executing an active development drilling program in the South Parachute area in 2004.

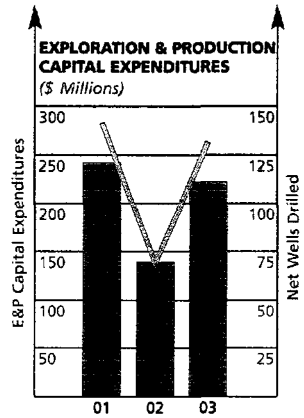
The Company produced an average of 30.1 Mmcfepd net for the year ended December 31, 2003, from the Piceance basin, as compared to 32.9 Mmcfepd net in 2002. The production decrease was a result of greatly-reduced drilling activity in the fourth quarter of 2002 followed by no wells being drilled in the Piceance in the first quarter of 2003 due to winter seasonal restrictions.

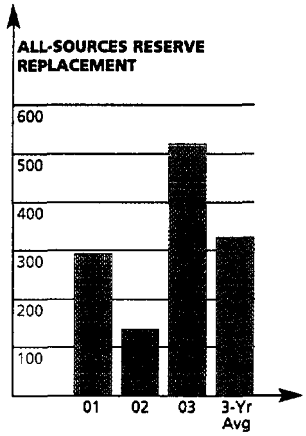
Paradox Basin

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 made up 11% and 20% of Tom Brown's year-end 2003 proved reserves and 2003 production, respectively.

Of the 15 gross wells drilled by the Company in the Paradox basin in 2003, primarily in the Andy's Mesa and Hamilton Creek fields, 13 were successful. With the success of the Andy's Mesa drilling program, the Company achieved record gross production levels of approximately 40 Mmcfepd from this field. TBI grew its Paradox basin production 19% in 2003 to a record level of 53.2 Mmcfepd as a result of the success at Andy's Mesa where the Company drilled nine wells with a 100% success rate.

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 relatively little exploration for this play type has occurred. TBI is exploring for new fields on its large acreage position in the basin due to our knowledge of and excellent results at Andy's Mesa.





Canada

Tom Brown's operations in western Canada represent 7% of total year-end 2003 reserves and 9% of 2003 production.

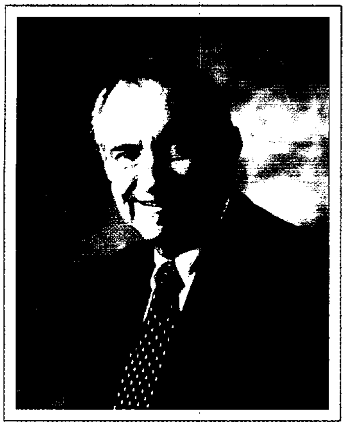
In 2003 TBI drilled 19 wells in Canada. By year end 13 had been completed, five were in the process of being completed and one was abandoned. In Canada, the Company produced an average of 24.1 Mmcfepd net in 2003 essentially unchanged from the 2002 level of 24.3 Mmcfepd.

Southern Area
(Permian, East Texas and South Texas)

The Southern area represents 36% and 31% of Tom Brown's year-end 2003 reserves and 2003 production, respectively. For the year-ended December 31, 2003, the Company drilled or participated in 121 gross wells in the Southern Area of which 93 had been completed, 13 were waiting to be completed and 15 were abandoned. Of the 121 gross wells drilled, 65 were in the East Texas basin, 54 were in the Permian basin and two were in South Texas. The Company produced an average of 81.8 Mmcfepd net for the year ended December 31, 2003 from the Southern Area compared to 49.2 Mmcfepd in 2002. The significant increase in production is a result of the contribution of production from the Matador acquisition beginning in the third quarter of 2003 along with our successful drilling program.

In East Texas, the Company had an active drilling program in the Bossier formation, drilling 60 wells in 2003 and achieving greater than a 97% success rate. Tom Brown has had excellent drilling results on the properties acquired from Matador Petroleum with a significant amount of activity at the Bank Stop/Loper, Goode Ranch, Bald Prairie and Nan-Su-Gail fields. In the Mimms Creek field (TBI 57% working interest), the Company participated in 22 gross wells. In January 2004, the Company commenced drilling the Crossman #2 (TBI 88.75% working interest), a potentially high-impact 15,700 foot wildcat targeting the expanded Cotton Valley section.

At the Deep Valley horizontal Devonian gas play in West Texas, the Company brought on the Horry Pitts 49-01H (TBI 50% working interest) at a rate of 15 Mmcfepd in December 2003 and it was still producing 12 Mmcfepd by the end of February 2004. TBI's Midland Division team members have been involved in exploiting tight gas carbonate reservoirs with horizontal drilling technology from its 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.



Mr. Thomas C. Brown founded the Company nearly fifty years ago. He has served on the Company's Board of Directors over the last 35 years. He resigned from the Board of Directors in May of 2003 and his unwavering dedication, knowledge, and integrity will be sorely missed.

In a business full of ups and downs Tom always managed to see opportunities and find the positive. He is a person who managed to achieve so much and help many people along the way. We will continue to work and live by his motto: "Always do the right thing." Thanks for everything, Tom.

— THE OFFICERS AND DIRECTORS OF TBI

Principal Officers

JAMES D. LIGHTNER
Chairman of the Board, Chief Executive Officer and President
Age: 51
Employed with the Company Since: 1999

THOMAS W. DYK
Executive Vice President and Chief Operating Officer
Age: 50
Employed with the Company Since: 1998

DANIEL G. BLANCHARD
Executive Vice President, Chief Financial Officer and Treasurer
Age: 43
Employed with the Company Since: 1999

PETER R. SCHERER
Executive Vice President and General Manager of the Midland Division
Age: 47
Employed with the Company Since: 1982

BRUCE R. DEBOER
Vice President, General Counsel and Secretary
Age: 51
Employed with the Company Since: 1997

DOUGLAS R. HARRIS
Vice President - Operations and General Manager of the Denver Division
Age: 49
Employed with the Company Since: 2001

RODNEY G. MELLOTT
Vice President - Land and Business Development
Age: 46
Employed with the Company Since: 1999

JOHN T. SANCHEZ
Vice President and General Manager of the Dallas Division
Age: 35
Employed with the Company Since: 2003

Board of Directors

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

DAVID M. CARMICHAEL
Private Investor

HENRY GROPPE
Partner in Groppe, Long & Littell

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

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

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

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

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

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the Fiscal Year Ended December 31, 2003

Or

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

For the Transition Period from to

Commission File Number 001-31308

Tom Brown, Inc.

(Exact name of registrant as specified in its charter)

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

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

The aggregate market value of the Registrant's Common Stock held by non-affiliates was approximately $1,098,754,323 as of June 30, 2003 (based on the last reported sale price of such stock on the New York Stock Exchange Composite Tape on that day).

As of March 5, 2004, there were 45,960,721 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive proxy statement for the 2004 Annual Meeting of Stockholders to be held on May 6, 2004 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 western Canadian Sedimentary Basin. The Company also, to a lesser extent, conducts exploration and development activities in other areas of the continental United States and Canada.

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

In June 2003, the Company completed its acquisition of Matador Petroleum Corporation ("Matador"), an exploration and production company active primarily in the East Texas Basin and Permian Basin of Southeastern New Mexico and West Texas.

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 gathering, processing and marketing of natural gas and (iii) the drilling of gas and oil wells.

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

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

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

BUSINESS STRATEGY

The Company's business strategy is to increase stockholder value through the discovery, acquisition and development of long-lived gas and oil reserves in areas where the Company has industry knowledge and operating 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 as was the Matador acquisition in 2003.

The Company's domestic and Canadian acreage position provides the Company with opportunities for future exploration and development activities. At December 31, 2003, the domestic acreage position was approximately 2,867,000 gross (1,866,000 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 Utah and Colorado, 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 62% of the net acreage is undeveloped. The Company's year-end Canadian acreage position located in western Alberta was approximately 531, 200 gross (342, 900 net) acres. Approximately 74% 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 estimated proved reserves in 2003 over 2002 by 52% due primarily to the Matador acquisition and continued drilling success in its core areas. Year-end estimated proved reserves were 1,137 billion cubic feet equivalent ("Bcfe"), compared to year-end 2002 estimated proved reserves of 750 Bcfe. At December 31, 2003, the Canadian estimated proved reserve base was 84 Bcfe compared to 82 Bcfe at December 31, 2002.

Reserve replacement for 2003 was 522% from all sources and 209% from extensions, discoveries and revisions only. The Company's estimated proved reserve to production ratio was 11.8 years at year-end 2003 compared to 8.8 years at year-end 2002. In addition to increasing reserves, the Company also increased its production 13% from 85.5 Bcfe in 2002 to 96.3 Bcfe in 2003.

Through 2003, the Company marketed 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. Effective January 1, 2004, this marketing activity will be conducted by the Company.

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 these acquisitions might involve the payment of cash and/or the issuance of equity or debt securities.

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

AREAS OF ACTIVITY

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

U.S. Rocky Mountain Region—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 56% of the Company's estimated proved reserves at December 31, 2003. The Company owns interests in 1,296 producing wells in these basins that averaged net daily production of 158 Mmcfe for 2003. The Company has approximately 1,601,000 gross (1,253,000 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 2003, the Company drilled and completed 15 wells in the Wind River Basin, the majority of which were located in the Frenchie Draw field. Additionally, in the Fuller/Deadman Hill area, the Company successfully drilled and completed two exploratory wells to the Fort Union interval in which Company holds an average interest of 80%. These successful wells have created a significant area of further potential drilling for the Company.

In the Piceance Basin, the Company drilled and completed 33 wells in 2003. This drilling occurred principally in the Parachute, Grand Valley and White River Dome areas. The Company's 2003 drilling program in the Parachute/South Parachute area totaled 11 wells (70% average working interest), achieving a 100% success rate. Due to an extensive field study and strong results this year in cost containment and completion efficiency, the Company has identified a significant inventory of future drilling locations in this basin.

The Company also drilled and completed 13 wells, in the Paradox Basin, primarily in the Andy's Mesa and Hamilton Creek fields. In the Green River Basin, the Company drilled and completed 13 wells.

The Rocky Mountain region has at times in the past, experienced limited natural gas transportation take-away capacity. Recognizing these restrictions, various companies have constructed pipelines and are continuing to add additional pipeline take-a-way capacity to transport gas from this area.

Southern Area—Permian, East Texas and South Texas Basins

The Southern Area accounted for approximately 36% of the Company's estimated proved reserves at December 31, 2003. The Company's share of production from these basins averaged 81.8 Mmcfepd for 2003. For the year ended December 31, 2003, the Company drilled and completed 93 wells. Of the 93 gross wells drilled and completed, 49 were in the East Texas Basin, 42 were in the Permian Basin and two were located in South Texas.

The Company drilled a development well at the Deep Valley project area, the Company's horizontal tight gas Devonian carbonate play in the Permian Basin. The Company holds a 50% working interest in this well that had an initial production rate of 15 Mmcfepd in December 2003 and was still producing above 12 Mmcfepd at the end of February 2004.

In the East Texas Basin, the Company has had an active drilling program in the Bossier Sands play, drilling 60 wells in 2003 and achieving greater than a 97% success rate. Tom Brown has had excellent drilling results in the fields acquired from Matador Petroleum with a significant amount of activity at the Bank Stop/Loper, Goode Ranch, Bald Prairie, and Nan-Su-Gail fields. In the Company's Mimms Creek field in the East Texas Basin (57% working interest) the Company participated in 22 gross wells in 2003.

Canadian Rocky Mountain Region—Western Sedimentary Basin

The Western Canadian Sedimentary Basin accounted for approximately 7% of the Company's estimated proved reserves at December 31, 2003. The Company's share of production from this basin averaged 24 Mmcfepd in 2003. The Company owns interests in 261 wells and has approximately 531,200 gross (342,900 net) developed and undeveloped acres in this area. In 2003, the Company drilled 19 wells in Canada of which 18 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 Matador

The Company entered into a definitive merger agreement on May 13, 2003 to acquire Matador Petroleum Corporation and the transaction closed on June 27, 2003. Matador was a privately held exploration and production company, active primarily in the East Texas Basin and Permian Basin of Southeastern New Mexico and West Texas, areas complementary to the Company's current areas of interest. The Company initially funded the acquisition with borrowings under a new $425.0 million senior unsecured bank credit facility and a $155.0 million loan under a senior subordinated credit facility. The Company subsequently issued 6 million shares of common stock in a public offering for net proceeds of $147.9 million and also issued $225 million of 7.25% senior subordinated notes in September 2003 to repay the $155 million bridge loan and reduce the borrowings outstanding under the bank credit facility.

The Matador transaction increased Tom Brown's estimated proved reserves by an estimated 269 Bcfe, of which 85% were natural gas reserves and 64% were proved developed. This acquisition was consistent with the Company's natural gas focus and increased the Company's concentration within two existing core areas; the East Texas Basin and the Permian Basin. These two regions represented 60% and 30%, respectively, of Matador's estimated equivalent proved reserves.

"See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations-Capital Resources and Liquidity-Debt" for a description of the material terms of the Company's bank credit facility and the Subordinated Credit Facility utilized to finance this transaction.

Acquisition of Rocky Mountain Assets

In May 2003, the Company purchased additional working interests from an unrelated third party in the Muddy Ridge field in the Wind River Basin of Wyoming. The acquired interests included an estimated 19.0 Bcfe of proved reserves purchased for total consideration of $17.4 million, net of normal closing adjustments.

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. The Company operates the assets in its subsidiary, Sauer Drilling Company ("Sauer"), which drills wells in the central Rocky Mountain region for the Company and other operators. The assets initially acquired included five drilling rigs, tubular goods, a yard and related assets. Subsequent to the acquisition, Sauer has acquired four additional drilling rigs for approximately $7 million and modernized the remainder of the fleet.

In 2004, the Company retained a financial advisor to evaluate the potential sale of Sauer.

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 2003 and 2002, there was a significant amount of volatility in the prices received for natural gas. Monthly closing gas prices in 2002 as measured on the New York Mercantile Exchange ("NYMEX") varied from a high of $4.14 per million British thermal units ("Mmbtu") for December 2002 to a low of $2.01 per Mmbtu for February 2002. In 2003, the NYMEX gas prices varied from a high of $9.13 per Mmbtu in March 2003 to a low of $4.43 per Mmbtu in October 2003. The U.S. Rocky Mountain region represented approximately 59% of the Company's 2003 gas production and 68% of its 2002 production. The price of gas in the Rocky Mountains at the Colorado Interstate Gas (CIG) hub was $1.35 and $1.25 per Mmbtu below the NYMEX posted gas price on average for 2003 and 2002, respectively. The Company's Canadian production base has also been subject to price volatility. In 2002, gas production from the Canadian fields was subject to gas pricing that ranged from $0.12 Mmbtu below the February 2002 NYMEX price to a price that was $1.24 per Mmbtu below the August 2002 NYMEX price. In 2003, the Canadian gas prices continued to be volatile ranging from $0.15 per Mmbtu below the NYMEX posting for July 2003 to $2.30 below the March 2003 NYMEX price.

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

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

PRODUCTION VOLUMES, UNIT PRICES AND COSTS

The following table sets forth certain information regarding the Company's volumes of production sold and average prices received associated with its production and sales of natural gas, natural gas liquids and crude oil for each of the years ended December 31, 2003, 2002 and 2001.

United States	Years Ended December 31, 2003	2002	2001
Production Volumes:			
Natural Gas (MMcf)	74,928	65,781	57,163
Crude Oil (MBbls)	850	623	723
Natural Gas Liquids (MBbls)	1,243	1,189	1,074
Net Average Daily Production Volumes:			
Natural Gas (Mcf)	205,282	180,221	156,611
Crude Oil (Bbls)	2,329	1,708	1,979
Natural Gas Liquids (Bbls)	3,406	3,258	2,943
Average Sales Prices:			
Natural Gas (per Mcf):			
Price received	$ 4.32	$ 2.10	$ 3.43
Effect of hedges	(.31)	—	0.30
Net sales price	$ 4.01	$ 2.10	$ 3.73
Crude Oil (per Bbl)	$ 28.90	$ 23.20	$ 22.64
Natural Gas Liquids (per Bbl)	$ 17.37	$ 11.39	$ 13.25
Average Production Cost (per Mcfe)(1)	$ .79	$ .57	$ .70

Canada	Years Ended December 31, 2003	2002	2001
Production Volumes:			
Natural Gas (MMcf)	6,331	6,386	6,661
Crude Oil (Mbbls)	208	220	158
Natural Gas Liquids (Mbbls)	202	193	143
Net Average Daily Production Volumes:			
Natural Gas (Mcf)	17,345	17,496	18,247
Crude Oil (Bbls)	569	601	432
Natural Gas Liquids (Bbls)	553	529	392
Average Sales Prices:			
Natural Gas (per Mcf):			
Price received	$ 5.49	$ 3.07	$ 3.49
Effect of hedges	(.71)	(0.03)	—
Net sales price	$ 4.78	$ 3.04	$ 3.49
Crude Oil (per Bbl)	$ 29.66	$ 23.86	$ 25.11
Natural Gas Liquids (per Bbl)	$ 24.63	$ 16.17	$ 20.23
Average Production Cost (per Mcfe)(1)	$ .70	$ .55	$ .62

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

CUSTOMERS

No one purchaser accounted for 10% or more of the Company's total gas and oil revenue during 2003. Because there are numerous parties available to purchase the Company's production, the

Company does not believe that the loss of a major purchaser would materially affect its ability to sell natural gas or crude oil.

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

COMPETITION

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

The principal raw materials and resources necessary for the exploration and development of natural gas and crude oil are leasehold prospects under which gas and oil reserves may be discovered, drilling rigs and related equipment to drill for and produce such reserves and knowledgeable personnel to conduct all phases of gas and oil operations. The Company must compete for such raw materials and resources with both major oil companies and independent operators.

EMPLOYEES

At December 31, 2003, the Company had 679 employees of which 252 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, states may regulate the rate of production and may establish maximum daily production allowables for wells on a market demand or conservation basis.

Oil Price Controls

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

Environmental Regulation

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

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

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

The Company currently owns or leases, and has in the past owned or leased, numerous properties that for many years have been used for the exploration and production of gas and oil. Although the

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

The Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other gas and oil wastes, into state waters or waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. These proscriptions also prohibit certain activity in wetlands unless authorized by a permit issued by the U.S. Army Corps of Engineers. The EPA has also adopted regulations requiring certain gas and oil exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans. The Company's management believes that the Company has obtained or applied for all permits required under the Clean Water Act. Sanctions for failure to comply with Clean Water Act requirement include administrative, civil and criminal penalties, as well as injunctive relief.

The Clean Air Act (CAA), as amended, restricts the emission of air pollutants from many sources, including natural gas and oil operations. New facilities may be required to obtain permits before work can begin, and existing facilities may be required to incur capital costs in order to remain in compliance. In addition, more stringent regulations governing emissions of toxic air pollutants are being developed by the EPA, and may increase the costs of compliance for some facilities. The Company's management believes that the Company is in substantial compliance with all air emissions regulations and that the Company has or has applied for all necessary permits for its operations. Management also believes that air emission permits for operation of the Company's Pavillion Gas Plant in Fremont County, Wyoming and Lisbon Gas Plant in Moab, Utah are material to the Company's operations. Currently, the Pavillion Gas Plant holds a Title V air emission operating permit that will not expire until January 9, 2009. The Lisbon Gas Plant was issued a Title V air emissions operating permit on September 30, 2002 that will not expire until September 30, 2007. The costs associated with obtaining and maintaining these permits are not material.

Indian Lands

The Company's Muddy Ridge and Pavillion Fields are located on the Wind River Indian Reservation. The Eastern Shoshone and Northern Arapaho Tribes levy taxes on the production of hydrocarbons. The Bureau of Indian Affairs, Minerals Management Service and Bureau of Land Management of the U.S. Department of the Interior perform certain regulatory functions relating to operation of Indian gas and oil leases. In December of 2000 the Company added to its Tribal base inventory around the Pavillion Field by signing ten 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 2004 until the agreement between the Tribes and the Company on a methodology for payment of Tribal gas royalties is approved and executed by the Tribal Council and the Minerals Management Service.

REGULATION—CANADA

Regulation of Gas and Oil Production and Price Controls

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

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

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

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime on Crown lands is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by government regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced.

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

In Alberta, certain producers of oil or natural gas are currently entitled to a credit against the royalties to the Crown by virtue of the ARTC (Alberta Royalty Tax Credit) program. The credit is determined by applying a specified rate to a maximum of $2 million CDN of Alberta Crown royalties payable for each producer or associated group of producers. The specified rate is a function of the Royalty Tax Credit Reference Price (RTCRP) which is set quarterly by the Alberta Department of Energy and ranges from 25% to 75%, depending on oil and gas 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 regulations pursuant to provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced or utilized in association with certain oil and gas industry operations. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. The Company operates within this regulatory framework and continues to monitor and evaluate the impact of the regulatory regime when determining parameters for engaging in gas and oil activities and investments in Canada. In addition, the Company routinely obtains permits for its facilities and operations in accordance with these applicable laws and regulations on an ongoing basis. There are no known issues that have a significant adverse effect on the permitting process or permit compliance status of any of the Company's facilities or operations.

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

ADDITIONAL INFORMATION

We electronically file certain documents with, or furnish such documents to, the Securities and Exchange Commission ("SEC"), including annual reports on Form 10-K, quarterly reports on Form 10-Q, and current reports on Form 8-K, along with any related amendments and supplements thereto. From time-to-time, we may also file registration and related statements pertaining to equity or debt offerings. You may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 450 Fifth Street, NW, Washington, DC 20549. You may obtain information regarding the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains an internet website at www.sec.gov that contains reports, proxy and information statements, and other information regarding issuers that file or furnish documents electronically with the SEC.

We provide free electronic access to our annual, quarterly, and current reports (and all amendments to these reports) on our internet website, www.tombrown.com. These reports are available on our website as soon as reasonably practicable after we electronically file or furnish such materials with or to the SEC.

Each of the Audit Committee, Compensation Committee and Corporate Governance and Nominating Committee has adopted committee charters which set forth respective purposes, duties and responsibilities including provisions for annual performance evaluations. The Company has also adopted Corporate Governance Guidelines, a Code of Business Conduct and Ethics, a Financial Code of Ethics for Senior Officers and Complaint Procedures for Financial, Accounting and Audit Matters. The charters and other governance guidelines, codes and procedures are available on the Company's website www.tombrown.com (click on tab "Corporate Information" and subtab "Corporate Governance").

Information on our website does not constitute part of this Annual Report. You may also contact our investor relations department at 303-260-5000 for printed copies of these reports, charters, guidelines, codes and procedures free of charge.

FORWARD-LOOKING STATEMENTS

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

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

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

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

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

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

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

RISK FACTORS

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

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

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

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

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

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

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

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

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

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

The Company reviews its gas and oil properties for impairment whenever events and circumstances indicate a decline in the recoverability of their carrying value. Once incurred, a writedown of gas and oil properties is not reversible at a later date even if gas or oil prices increase. Given the complexities associated with gas and oil reserve estimates and the history of price volatility in the gas and oil markets, events may arise that would require the Company to record an impairment of the recorded book values associated with gas and oil properties. In 2003, the Company recognized a pre-tax impairment of $7.8 million on certain gas and oil properties in the James Lime play in East Texas after drilling results in these areas to date have proved to be only marginally successful. The impairment represents the excess of the Company's carrying cost of these properties over the estimated fair value of the related proved oil and natural gas reserves as of December 31, 2003. In 1998, the Company recognized a pre-tax impairment of $51.3 million, primarily as a result of the low market prices in effect at that time. Similar impairments may be required in the future.

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

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

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

The Company's revenues are derived principally from uncollateralized sales to customers in the gas and oil industry. The concentration of credit risk in a single industry affects the Company's overall exposure to credit risk because customers may be similarly affected by changes in economic and other conditions. The publicly disclosed deteriorating financial conditions and recently reduced credit ratings of certain purchasers of production increase the possibility that the Company may not receive payment for a portion of its future production. In 2002, a previous purchaser of the Company's natural gas liquids in the Paradox Basin of Colorado and Utah defaulted on payments owed the Company totaling $6.2 million; the Company received a $1.4 million cash settlement in connection with this default. The Company has attempted to obtain credit protections such as letters of credit, guarantees and prepayments from certain of it purchasers. The Company is unable to predict, however, what impact the financial difficulties of certain purchasers may have on its future results of operations and liquidity.

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

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

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

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

At December 31, 2003, approximately 32% of the Company's U.S. estimated proved reserves were proved undeveloped, while 15% of the Company's Canadian estimated proved reserves were proved undeveloped. Proved undeveloped reserves and proved developed non-producing reserves, by their nature, are less certain than proved developed producing reserves. Estimation of these non-producing categories is nearly always based on volumetric calculations rather than the performance data used to estimate producing reserves. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Production revenues from proved non-producing reserves will not be realized until some time in the future. The reserve data assumes that the Company will make significant capital expenditures to develop its reserves. Although the Company has prepared estimates of its gas and oil reserves and the costs associated with these reserves in accordance with industry standards, these estimated costs may not be accurate, development may not occur as scheduled and actual results may not be as estimated.

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

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

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

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

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

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

The Company spends and will continue to spend a substantial amount of capital for the acquisition, exploration, exploitation, development and production of gas and oil reserves. If low natural gas and oil prices, operating difficulties or other factors, many of which are beyond the Company's control, cause its revenues and cash flows from operating activities to decrease, the Company may be limited in its ability to spend the capital necessary to complete its capital expenditures program. In addition, if the Company's borrowing base under its credit facility is re-determined to a lower amount, this could adversely affect the Company's ability to fund its planned capital expenditures. The Company's capital expenditures, including acquisitions, were $656.3 million during 2003, $161.7 million during 2002 and $358.1 million during 2001. The Company anticipates capital and exploration expenditures between $275 and $325 million in 2004, approximately 90% of which will be allocated to exploration and development activity. After utilizing its available sources of financing, the Company may be forced to raise additional equity or debt proceeds to fund such expenditures. Additional equity or debt financing or cash flow provided by operations may not be available to meet the Company's capital expenditures requirements.

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

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

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

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

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

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

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

New wells that the Company drills may not be productive and the Company may not recover all or any portion of its investment. The cost of drilling and completing wells is often uncertain. Drilling for natural gas and oil may be unprofitable. Drilling activities can result in dry wells and wells that are productive but do not produce sufficient net revenues after operating and other costs to recoup drilling costs.

The Company's industry experiences numerous operating risks.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require the Company to make significant expenditures to maintain compliance, and may otherwise have a material adverse effect on the earnings, results of operations, competitive position or financial condition of the Company. Over the years, the Company has owned or leased numerous properties for gas and oil activities upon which petroleum hydrocarbons or other materials may have been released by the Company or by predecessor property owners or lessees who were not under the Company's control. Under applicable environmental laws and regulations, including CERCLA, RCRA and analogous state laws, the Company could be held strictly liable for the removal or remediation of previously released materials or property contamination at such locations regardless of whether the Company was responsible for the release or if the Company's operations were standard in regulations to which the Company is subject, see "—Regulation—United States—Environmental Regulation."

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

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

Hedging transactions may limit the Company's potential gains.

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

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

The Company does not pay dividends.

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

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

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

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

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

ITEM 2. *Properties*

GAS AND OIL PROPERTIES

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

TITLE TO PROPERTIES

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

ACREAGE

The following table sets forth the gross and net acres of developed and undeveloped gas and oil leases held by the Company at December 31, 2003. 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	106,908	86,702	543,593	472,703
Louisiana	1,419	671	2,648	2,648
Montana	102	76	158,307	26,443
North Dakota	—	—	2,960	80
Nebraska	—	—	31,455	30,861
New Mexico	60,267	30,367	69,215	50,271
Oklahoma	12,142	3,522	3,985	128
Texas	224,602	71,689	442,813	274,588
Utah	6,399	5,621	113,244	101,891
West Virginia	3,852	1,240	147,120	72,936
Wyoming	131,439	70,445	803,003	561,930
Canada	154,900	89,300	376,300	253,600
Other	360	360	713	522
Total	702,390	359,993	2,695,356	1,848,601

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

GAS AND OIL RESERVES

Estimates of the Company's gas, oil and natural gas liquids reserves, including future net revenues and the present value of future net cash flows, were prepared by the Company's petroleum engineering staff and reviewed by Ryder Scott (independent petroleum consultants). Guidelines established by the Securities and Exchange Commission were utilized to prepare these reserve estimates. Estimates of gas, oil and natural gas liquids reserves and their estimated values require numerous engineering assumptions as to the productive capacity and production rates of existing geological formations and require the use of certain Securities and Exchange Commission guidelines as to assumptions regarding costs to be incurred in developing and producing reserves and prices to be realized from the sale of future production.

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

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

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

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

PRODUCTIVE WELLS

The following table sets forth the gross and net productive gas and oil wells in wells in which the Company owned an interest at December 31, 2003.

	Productive Wells			
	Gross		Net	
	Gas	Oil	Gas	Oil
Colorado	579	4	382.3	3.1
Louisiana	4	—	2.0	—
Nebraska	1	—	0.1	—
New Mexico	223	135	90.0	75.6
Oklahoma	40	15	8.5	3.8
Texas	524	104	255.4	28.1
Utah	9	19	8.2	18.9
West Virginia	91	—	33.4	—
Wyoming	676	9	347.6	4.6
Canada	170	91	59.7	60.7
Total	2,317	377	1,187.2	194.8

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.

	Year ended December 31, 2003					
	United States			Canada		
Type of Well	Gross	Net	Net%	Gross	Net	Net%
Exploratory						
Gas	9	4.7	40	1	1	50
Oil	4	1.4	17	—	—	—
Dry	10	6.4	43	1	0.8	50
	23	12.5	100	2	1.8	100
Development						
Gas	167	91.7	92	15	12.5	88
Oil	5	3.6	3	2	1.5	12
Dry	10	6.4	5	—	—	—
	182	101.7	100	17	14	100
Total	205	114.2		19	15.8	

	Year ended December 31, 2002					
	United States			Canada		
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	Year ended December 31, 2001					
	United States			Canada		
	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	26.2	

At December 31, 2003, 35 gross (17.7 net) development wells and 2 gross (.3 net) exploratory wells were in various stages of drilling and completion in Texas, Colorado, and Wyoming, while 6 gross (5 net) development wells and 1 gross and (1 net) exploratory well were in various stages of drilling and completion in Canada. The investment in the exploratory wells in progress was approximately $5 million at December 31, 2003.

OTHER PROPERTIES

The Company leases its corporate office facilities in Denver, Colorado. The lease covers approximately 56,500 square feet. This lease was renegotiated effective November 1, 2003 and extended through May 31, 2011.

The Company leases office facilities in Midland, Texas. The lease covers approximately 34,600 square feet and this lease was extended in 2003 for an additional five-year term that will end on December 31, 2008.

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.

As a result of the Matador transaction in 2003, the Company committed to a new seven-year office lease in Dallas, Texas for 22,300 square feet that expires on December 31, 2010.

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

ITEM 3. ***Legal Proceedings***

The Company is a defendant in certain routine legal proceedings incidental to its business none of which are expected to have a material adverse affect on the Company.

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 CERCLA) in Waller County, Texas (the "Sheridan Superfund Site"). Effective August 31, 1989, Rocno and thirty-six other defendants executed the Sheridan Site Trust Agreement (the "Trust") for the purpose of creating a trust to perform agreed upon remedial action at the Sheridan Superfund Site. In connection with the establishment of the Trust, the parties to the Trust agreed to the terms of a Consent Decree entered December 3, 1991 in the United States District

Court, Southern District of Texas, Houston Division, Civil Action No. H-91-3529, pursuant to which the defendants joining the Consent Decree will carry out the clean-up plan prescribed by the Consent Decree. In December 2002, the EPA approved a change in the remedy that was originally selected for clean-up of the Sheridan Superfund Site by eliminating the biotreatment of site wastes prior to stabilization and capping of the wastes. The EPA is currently amending the Consent Decree to include the revised remedy. The estimate of the total clean-up cost under the revised remedy is approximately $14.3 million. Under terms of the Trust, each party is allocated a percentage of costs necessary to fund the Trust for clean-up costs. Rocno's proportionate share of the estimated clean-up costs is 0.33% or $47,200, of which $16,000 has been paid, and the remainder was accrued in the Company's consolidated financial statements. If the clean-up costs exceed the projected amount, Rocno will be required to pay its pro rata share of the excess clean-up costs.

The Company was 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 was one of more than a dozen virtually identical class action lawsuits filed in various Wyoming courts against producers and operators in Wyoming. The complaint alleged 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 was 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. Pending the resolution of these issues by the Wyoming Supreme Court, the Company elected to settle the violations alleged against the Act effective September 30, 2003 for a settlement amount of $4.2 million. The settlement established a future royalty payment methodology to allow the Company a safe harbour to remain in compliance with the Act and provided the Company with the ability to opt out of the methodology when an ultimate decision is reached by the Wyoming Supreme Court as to the deductibility of transportation costs as a production cost.

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, 2003.

Executive Officers of the Registrant

The executive officers of the Company on March 11, 2004 were as follows:

Name	Age	Position with Company
James D. Lightner	51	Chairman, Chief Executive Officer and President
Thomas W. Dyk	50	Executive Vice President and Chief Operating Officer
Daniel G. Blanchard	43	Executive Vice President, Chief Financial Officer and Treasurer
Peter R. Scherer	47	Executive Vice President and General Manager—Midland Division
Bruce R. DeBoer	51	Vice President, General Counsel and Secretary
Douglas R. Harris	49	Vice President—Operations and General Manager—Denver Division
Rodney G. Mellott	46	Vice President—Land and Business Development
John T. Sanchez	35	Vice President and General Manager—Dallas Division

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

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

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

Thomas W. Dyk joined the Company in April 1998 as Executive Vice President and was subsequently named the Company's Chief Operating Officer in 1999. Prior to joining Tom Brown, Mr. Dyk served as Regional Vice President for the Rocky Mountain Division of Burlington Resources. He served in various technical and management capacities from 1983 to 1996 while at Burlington Resources.

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

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

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

Douglas R. Harris joined the Company in February 2001 as Vice President and was subsequently named Vice President and General Manager—Denver Division. From February 1986 through January 2001, he served as Vice President—Production for Burlington Resources Canada in Calgary.

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

John T. Sanchez joined the Company in August 2003 as the General Manager of the Dallas Division and was subsequently appointed a Vice President of the Company in November 2003. Mr. Sanchez was the Vice President of Corporate Development and Reservoir Engineering for Bill Barrett Corporation and held similar positions with Westport Resources and Morningstar Energy LLC prior to joining Tom Brown.

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 quotations for each quarterly period during the past two fiscal years as reported by NASDAQ National Market System for the March 31, 2002 period, and the NYSE for the June 30, 2002 through December 31, 2003 periods.

Quarter Ended	Sale Price High	Sale Price Low
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
March 31, 2003	26.02	23.00
June 30, 2003	29.00	23.61
September 30, 2003	27.95	24.49
December 31, 2003	32.66	25.98

On March 8, 2004 the last sale price of the Company's Common Stock, as reported by the New York Stock Exchange was $35.91 per share.

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

In September 2003, the Company issued 6 million shares of common stock at a price of $25.75 per share. Net proceeds from this offering were $147.9 million after deducting underwriting discounts, commissions and offering expenses. The proceeds from this offering were utilized by the Company to retire debt.

On December 31, 2003, the outstanding shares of the Company's Common Stock (45,669,313 shares) were held by approximately 1,706 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 allowed to pay up to $40 million of cash dividends to the holders of Common Stock without the written consent of the bank lenders.

On March 1, 1991, the Board of Directors adopted, and amended and restated as of March 1, 2001, a Rights Plan designed to help assure that all stockholders receive fair and equal treatment in the event of a hostile attempt to take us over, and to help guard against abusive takeover tactics. Each outstanding share of our Common Stock includes one preferred share purchase right (a "Right"). Each Right entitles the registered holder of our Common Stock to purchase, for each share of Common Stock they own, additional shares of our Common Stock or other securities of the Company (or, under certain circumstances, of the acquiring person) with a market value worth twice the $120 per share exercise price of the Right.

The Rights will be exercisable only if a person or group acquires 15% or more of Common Stock or announces a tender offer which would result in ownership by a person or group of 15% or more of our 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.

Until the Distribution Date occurs, the certificates representing shares of our 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 us that are not approved by the Board of Directors and thereby deprive the stockholders of opportunities to sell their shares of Common Stock at prices higher than the prevailing market price. See "Risk Factors." On the other hand, these provisions will tend to assure continuity of management and corporate policies and to induce any person seeking control of us or to complete a business combination with us to negotiate with the elected Board of Directors.

ITEM 6. *Selected Financial Data*

The following table sets 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 Matador Acquisition in June 2003, the Stellarton Acquisition in January 2001 and the Unocal Acquisition in July 1999. (See the Notes to Consolidated Financial Statements included elsewhere herein.) The selected financial information should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Company's Consolidated Financial Statements.

	Years Ended December 31,				
	2003	2002	2001	2000	1999
	(In thousands, except per share amounts)				
Revenues	$ 467,607	$ 289,268	$ 449,100	$ 362,280	$191,935
Income (loss) before cumulative effect of change in accounting principle	83,666	9,926	67,477	65,703	5,007
Net income (loss) attributable to common stock(1)	82,737	(8,177)	69,503	65,703	5,007
Weighted average number of common shares outstanding					
Basic	41,260	39,217	38,943	36,664	32,228
Diluted	42,365	40,327	40,227	37,897	32,466
Net income (loss) per common share					
Basic	$ 2.01	$ (.21)	$ 1.78	$ 1.79	$ .16
Diluted	1.95	(.20)	1.73	1.76	.15
Total assets	$1,568,434	$ 850,952	$ 844,975	$ 629,535	$536,299
Long-term debt, net of current maturities	394,080	133,172	120,570	54,000	81,000
Other Financial Data:					
Net cash provided by operating activities	$ 237,304	$ 121,562	$ 207,900	$ 132,958	$ 38,857
Net cash used in investing activities	(487,525)	(137,171)	(276,987)	(117,738)	(54,999)
Net cash provided by (used in) financing activities	270,741	13,972	66,975	(10,196)	25,982

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

The following table sets forth selected information for the Company's proved reserves for each of the years shown.

	Years Ended December 31,				
	2003	2002	2001	2000	1999
Proved reserves at period end:					
Gas (Mmcf)	1,041,828	674,037	641,579	535,373	445,933
Oil (MBbls)	9,774	6,025	6,647	6,116	6,735
Natural Gas Liquids (MBbls)	6,134	6,655	8,360	5,077	6,266
Discounted future net cash flows before income taxes (in thousands)	$2,221,130	$883,353	$501,288	$2,187,925	$393,423

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

EXECUTIVE SUMMARY

Overview

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

On a reserve volume basis, approximately 56% of the Company's proved reserves are located in the Rocky Mountain Region which are managed from the Denver Division, approximately 36% of the proved reserves are located in the southern area and managed by the Dallas and Midland Divisions and 7% of the Company's proved reserves are located within the Canadian Rocky Mountain Region managed from the Calgary office.

In June 2003, the Company completed its acquisition of Matador Petroleum Corporation ("Matador"), an exploration and production company active primarily in the East Texas Basin and Permian Basin of Southeastern New Mexico and West Texas. As a result of this acquisition and continued drilling success in the Company's focus areas, the Company increased its reserves in 2003 by 52%. Continued drilling success in its core areas also contributed to the increase in reserves. The Company participated in the drilling of 205 wells in 2003 of which 185 wells (90%) were successful. In 2002, the Company participated in 81 wells of which 71 wells (88%) were successful.

Year-end proved reserves were 1,137 Bcfe, compared to year-end 2002 reserves of 750 Bcfe. At December 31, 2003, the Canadian reserve base was 84 Bcfe compared to 82 Bcfe at December 31, 2002.

Production

In 2003, the Company's production volumes averaged 263.8 Mmcfepd, a 13% increase over the 234.3 Mmcfepd in 2002.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The discussion and analysis of the Company's financial condition and results of operations is 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. The Company's significant accounting policies are described in the notes to our consolidated financial statements which are included elsewhere in this annual report. The Company has identified certain of these policies as being of particular importance to the portrayal of the Company's financial position and results of operations and which require the application of significant judgment by management. The Company analyzes its estimates, including those related to the accounting for oil and gas revenues, bad debts, gas and oil properties, marketable securities, income taxes, derivatives, contingencies and litigation, and bases its estimates on historical experience and various other assumptions that the Company believes to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. The Company believes the following critical accounting policies relate to the more significant judgments and estimates used in the preparation of the Company's financial statements:

Successful Efforts Method of Accounting

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

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

The successful efforts method of accounting can have a significant impact on the operational results reported when the Company is entering a new exploratory area in hopes of finding a gas and oil field that will be the focus of future development drilling activity. Any initial exploratory wells that are unsuccessful are expensed. Exploration 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, estimates of 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.

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 2003, the Company recognized a pre-tax impairment of $7.8 million on certain gas and oil properties in the James Lime play in East Texas after drilling results in these areas to date proved to be only marginally successful. The impairment represents the excess of the Company's carrying cost of these properties over the estimated fair value of the related proved oil and natural gas reserves as of December 31, 2003. There were no impairments of producing gas and oil properties in 2002 or 2001.

Derivative Instruments and Hedging Activities

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

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

RESULTS OF OPERATIONS

The following analysis of operations for the years ended December 31, 2003, 2002 and 2001 should be read in conjunction with the Consolidated Financial Statements and associated footnotes included in this Form 10-K.

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

Excluding the cumulative effect of changes in accounting principles, the Company realized net income for the year ended December 31, 2003 of $83.7 million or $1.97 per share (diluted basis) as compared to net income of $9.9 million or $0.25 per share (diluted basis) for the same period in 2002. The majority of this increase was attributable to higher commodity prices in 2003 and a 13% increase in production volumes. Excluding the cumulative effect of change in accounting principle, the Company realized net income of $67.5 million or $1.68 per share (diluted basis) in 2001. The majority of the Company's production is natural gas and these general earnings trends were impacted significantly by the natural gas prices in each of these periods. The average realized natural gas price for 2003, 2002 and 2001 was $4.07 per Mcf, $2.19 per Mcf and $3.71 per Mcf, respectively.

The Matador Petroleum Corporation acquisition on June 27, 2003 also impacted the results reported by the Company in 2003. Incremental gas and oil revenues contributed by the Matador properties subsequent to the acquisition were $55.1 million in 2003. The production taxes on these revenues were $4.1 million and gas and oil production expenses of $6.9 million were incurred. Additionally, this acquisition impacted general and administrative expenses and the incremental production caused a corresponding increase in depreciation, depletion and amortization expense in 2003.

The net income/loss recognized in the years ended December 31, 2003, 2002 and 2001 were impacted by the adoption of new accounting principles during these periods. Effective January 1, 2003, the Company adopted the new accounting standard SFAS No 143 "Accounting for Asset Retirement Obligations" (SFAS No. 143). SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation. As a result of adopting SFAS 143, the Company recorded a non-cash charge of $.9 million (net of a deferred tax benefit of $.6 million) as the cumulative effect of the change in accounting principle. On January 1, 2002, the Company adopted the new accounting standard, SFAS No. 142 "Goodwill and Other Intangible Assets" (SFAS No. 142). The Company conducted a fair value based test effective January 1, 2002 to evaluate the goodwill originally recorded in conjunction with the January 2001 Stellarton Energy Corporation acquisition. The fair value of the reporting unit was determined with reference to the estimated discounted future net revenues of the underlying gas and oil reserves as of the date of the test and other financial considerations including going-concern value. This test resulted in the Company recording a non-cash charge of $18.1 million in the quarter ended March 31, 2002 as the cumulative effect of a change in accounting principle. 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 2003 revenues from gas, oil and natural gas liquids production increased 100% to $387.7 million, as compared to $194.3 million in 2002. This increase was the result of (i) an increase in average gas prices received by the Company from $2.19 per Mcf in 2002 to $4.07 per Mcf in 2003, which increased revenues $135.7 million, (ii) an increase in average oil and natural gas liquids prices received from $16.35 to $22.89 per Bbl which increased revenues $14.6 million, (iii) an increase in gas sales volumes of 13% to 81.3 Bcf which increased revenues by $37.0 million, and (iv) an increase in oil and natural gas liquids sales volumes of 13% to 2.5 million barrels, which increased revenues by $6.1 million.

Revenues in 2003 were impacted by cash payments required on hedging activities. Settlements on our collar and swap agreements, all of which were considered effective hedges, were $27.7 million, which reduced gas and oil sales in 2003.

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 per Bbl which decreased revenues $3.4 million partially offset by, (iii) an increase in gas sales volumes of 13% to 72.2 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.

Revenues in 2001 were also impacted by cash gains realized from hedging activities. Settlements on our collar and swap agreements, all of which were considered effective hedges were $15.9 million, which were included in gas and oil sales in 2001.

The revenues contributed by the Stellarton transaction for the period subsequent to the closing date of January 12, 2001 were $41.4 million in 2003 and $27.8 million in 2002 and $30.1 million in 2001.

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,		
	2003	2002	2001
		(In thousands)	
Revenues:			
Natural gas sales	$330,384	$157,881	$236,551
Crude oil sales	30,720	19,733	20,350
Natural gas liquids sales	26,568	16,662	17,130
Gathering and processing	19,912	20,467	23,245
Marketing and trading	37,022	58,899	124,667
Drilling	19,857	14,347	14,828
Cash (paid) received on derivatives	—	(2,061)	4,121
Change in derivative fair value	1,913	(345)	(3,224)
Gain on sale of property	—	4,114	10,078
Interest income and other	1,231	(429)	1,354
Total revenues	$467,607	$289,268	$449,100

	Years Ended December 31,		
	2003	2002	2001
Natural gas production (Mmcf)	81,258	72,167	63,824
Crude oil production (MBbls)	1,058	843	881
Natural gas liquid production (MBbls)	1,445	1,382	1,217
Average natural gas sales price ($/Mcf)(1)	$ 4.07	$ 2.19	$ 3.71
Average crude oil sales price ($/Bbl)	$ 29.05	$ 23.41	$ 23.09
Average natural gas liquid sales price ($/Bbl)	$ 18.38	$ 12.05	$ 14.07

(1) Net of the impact of hedging activities

Gathering and processing revenues decreased 3% to $19.9 million in 2003 compared to $20.5 million in 2002 which was principally the result of declining production volumes from the Company's Wind River Basin Indian Reservation properties where drilling has been deferred until an agreement can be reached on the method of payment for Tribal gas royalties. In 2002, gathering and processing revenue decreased 12% to $20.5 million, as compared to $23.2 million in 2001. Gathering and processing revenue in 2002 declined compared to 2001 as a number of non-strategic gathering and processing assets were sold in 2001.

Marketing and trading revenue decreased to $37.0 million in 2003 from $58.9 million in 2002 and $124.7 million in 2001. The Company reduced the natural gas volumes associated with trading contracts in 2003 which resulted in a reduction in trading revenue. In 2001, trading revenues were higher than in 2002 given the correspondingly higher natural gas prices in this period.

Marketing and trading income, net of associated expenses decreased to $0.2 million in 2003 from a net margin of $5.3 million in 2002. The net margin realized in 2002 benefited from the Company transporting gas into the Mid-Continent region to take advantage of higher gas prices in this market utilizing the Company's firm transportation. This pricing differential was not available due to a change in market conditions in 2003. 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 $0.29 Mmbtu margin (after transportation costs) on gas moved into the Mid-Continent region.

Drilling revenue associated with the Company's wholly owned subsidiary, Sauer, increased 38% for the year ended December 31, 2003, compared to the same period in 2002. In 2003, Sauer generated a higher percentage of its contract drilling revenue from third-party contracts not affiliated with the Company, as compared to 2002. This change in mix resulted in higher drilling revenues in 2003. Drilling revenue also benefited from an increase in rig utilization rates from 70% in 2002 to 83% in 2003 and from the addition of the ninth rig in August 2003.

Drilling revenue remained relatively unchanged in 2002, as compared to 2001, 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 the revenue 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.

Costs and Expenses

In 2003, expenses related to gas and oil production increased 30% from $32.2 million in 2002 to $41.9 million in 2003. The incremental gas and oil production expenses incurred on the Matador properties accounted for $6.9 million of this increase. On an Mcfe basis, the incremental Matador gas and oil production expenses were $0.57 per Mcfe which was the primary reason consolidated gas and oil production costs increased from $0.38 per Mcfe to $0.44 per Mcfe in 2003. The Company also incurred workover expenses and plant turnaround expenses on a Canadian facility in 2003 which increased the total and per Mcfe gas and oil production expenses.

Expenses related to gas and oil production remained flat from 2001 to 2002 despite increased production. On an Mcfe basis, gas and oil production costs decreased to $.38 in 2002 from $0.42 in 2001 as a result of a continued focus on cost containment and higher production volumes.

Taxes on gas and oil production increased by 99%, or $16.5 million, in 2003 due to the 100% increase in revenues from gas and oil sales realized in 2003.

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. Additionally, $15.9 million was realized on the natural gas hedge transactions and 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 $20.2 million in 2003 as compared to 2002. The acquisition of Matador, and the resulting incremental production, was the primary reason for this increase. On an Mcfe basis, the effective depreciation, depletion and amortization rate increased to $1.06 in 2003 from $.95 in 2002. The increase in 2003 is generally attributable to the acquisition of the Matador properties at an approximate cost of $1.49 Mcfe.

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 $0.95 per Mcfe as compared to $0.83 per Mcfe in 2001.

Gathering and processing costs principally represent costs associated with operating and maintaining the field systems. This expense increased $0.4 million in 2003 as compared to 2002. The increase was attributable to incremental processing costs associated with marketing third-party liquids through the Lisbon plant in the Paradox basin.

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 $29.5 million, $22.8 million and $34.2 million for the years 2003, 2002 and 2001, respectively. Exploration expense for these periods was impacted by the dry hole costs of $10.3 million, $7.8 million and $15.8 million recognized in 2003, 2002 and 2001, 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 $656.3 million, which includes $388 million for the Matador acquisition, were incurred in 2003 compared to $161.7 million in 2002. The 2003 exploration, development and land related expenditures were $232 million, an increase of 67% in comparison to 2002. The 2002 exploration, development and land related expenditures were $139 million, a decrease of 43% in comparison to 2001. 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 and the actual results of the exploration efforts. 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 $.28, $.22, and $.30 for the years 2003, 2002 and 2001, respectively. Of the $8.9 million increase in general and administrative costs recognized in 2003 as compared to 2002, approximately $5 million was associated with the incremental personnel costs and other transitional related expenses associated with the Matador transaction. The general and administrative expenses in 2003 also increased $1.9 million due to increased corporate insurance costs for both the general corporate liability coverages and the personnel health plan coverages. General and administrative expense for 2003 included a $0.4 million pre-tax charge associated with charge for stock compensation for a retiring director as a result of an earlier amendment to the terms of an option grant and a $0.4 million charge for the amortization of restricted stock grants.

General and administrative expenses in 2001 of $22.7 million were $4.3 million higher than the expenses recognized in 2002. Included in the expenses for 2001 was a $5.3 million ($.07 per Mcfe) pre-tax charge recorded in the first quarter of 2001 associated with the retirement of Donald L. Evans, the Company's former Chairman and CEO. Mr. Evans received a $1.5 million retirement payment and the Company recognized a $3.8 million non-cash charge in conjunction with the acceleration of Mr. Evans' stock options.

Bad debt expense in 2002 reflected the impact of the 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 provision originally recorded.

Interest and other expense increased in 2003 by $16.7 million, as compared to 2002. Incremental interest expense was incurred in 2003 as a result of financing the majority of the Matador transaction through increased long-term debt (approximately $150 million of this acquisition was financed by the issuance of common stock). The resulting impact of this transaction was to increase the combined long-term debt of the Company from $133.2 million at December 31, 2002 to $394.1 million at December 31, 2003. Additionally incremental interest expense was incurred in 2003 on the Senior Subordinated Notes at 7.25%, which is approximately three percentage points higher than the interest rate on the New Global Credit Facility. Loan origination costs of $3.6 million were expensed in 2003 associated with the bridge loan secured to initially finance the Matador transaction. Other expense in 2003 included $2.1 million of costs associated with the non-compete agreements entered into with certain of the former officers of Matador, and $3.0 million associated with the settlement of the Wyoming lawsuit.

Interest and other expense in 2002 was impacted by standby fees incurred under the terms of a two-year commitment entered into in 2001 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 $35.0 million, $3.2 million and $38.1 million in 2003, 2002, and 2001, respectively, resulting in effective tax rates of 29.5%, 29.4% and 36.1%, respectively. The 2003 income tax provision of $35.0 million was impacted by the enactment of a Canadian Federal tax reduction for which a $6.5 million tax benefit was recognized. The 2003 tax provision also was impacted by a refund of $1.4 million of Canadian taxes relating to an earlier tax period and by a $2.4 million tax reduction associated with certain Canadian expenses also deductible in the United States.

The 2002 income tax provision of $3.2 million was also impacted by the tax reduction ($1.6 million) 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, 2003, the Company has a net operating loss carryforward available for U.S. Federal tax purposes of $58.0 million. Additionally, statutory depletion carryforwards of approximately $7.2 million and $5.2 million of alternative minimum tax credit carryforwards are available in the U.S. to offset future taxes. Based upon the operating results for 2003 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 should benefit from its financing flexibility and the leverage potential of the Company's overall capital structure.

The Company entered into a definitive merger agreement on May 13, 2003 to acquire Matador Petroleum Corporation and the transaction closed on June 27, 2003. Matador was a privately held exploration and production company, active primarily in the East Texas Basin and Permian Basin of Southeastern New Mexico and West Texas, areas complementary to the Company's existing areas of interest. The Company initially funded the acquisition with borrowings under a new $425.0 million senior unsecured bank credit facility and a $155.0 million loan under a senior subordinated credit facility. The Company issued 6.0 million shares of common stock for net proceeds of $147.9 million and issued $225 million of 7.25% senior subordinated notes in September 2003 to repay the $155 million bridge loan and reduce the borrowings outstanding under the bank credit facility.

In May 2003, the Company also purchased additional working interests from an unrelated third party in the Muddy Ridge field operated by the Company in the Wind River Basin of Wyoming. The acquired interests included an estimated 19.0 Bcfe of estimated proved reserves purchased for total consideration of $17.4 million net of normal closing adjustments.

Capital and Exploration Expenditures

The Company's capital and exploration expenditures and sources of financing for the years ended December 31, 2003, 2002 and 2001 are as follows:

	2003	2002	2001
		(In millions)	
CAPITAL AND EXPLORATION EXPENDITURES:			
Acquisitions:			
Matador	$388.0	$ —	$ —
Stellarton	—	—	95.0
Rocky Mountain assets and other	19.8	15.9	3.3
Exploration costs	50.1	33.2	56.0
Development costs	171.9	94.6	163.2
Acreage	10.4	10.9	22.6
Gas gathering and processing	8.0	4.7	9.3
Sauer Drilling Company	4.9	.9	5.2
Other	3.2	1.5	3.5
	$656.3	$161.7	$358.1
FINANCING SOURCES:			
Cash flow provided by operating activities	$237.3	$121.6	$207.9
Net proceeds from common stock issued	147.9	—	—
Net proceeds from issuance of senior subordinated notes	220.0	—	—
Net long term bank debt (repayments) borrowings	(94.3)	11.8	55.8
Debt assumed on Stellarton transaction	—	—	16.8
Debt assumed on Matador acquisition	114.5	—	—
Proceeds from sale of assets	15.7	10.8	52.4
Proceeds from exercise of stock options	4.2	2.2	11.2
Other	11.0	15.3	14.0
	$656.3	$161.7	$358.1

The Company anticipates capital and exploration expenditures between $275 to $325 million in 2004, at least 95% 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 internally generated cash, borrowings and equity financings.

Property Sales

In December 2003, the Company sold certain of its' interest in gas and oil properties located in the Permian Basin of Texas to an unrelated third party for net cash proceeds of $12.9 million. The resulting gain was not significant.

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

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

In 2001, $52.4 million in cash proceeds were derived from property sales. In May 2001, the Company sold its interest in gas and oil properties located in Oklahoma to an unrelated third party. These properties had a net book basis of $14.4 million. This transaction resulted in a gain of $10.1 million with net cash proceeds of $24.5 million. Cash proceeds of $24 million were also realized in conjunction with several sales transactions in 2001 associated with the disposition of gathering and processing facilities received in the Wildhorse distribution in November 2000.

Contractual Obligations and Debt

In addition to the bank credit facility and the senior subordinated notes, the Company had various other contractual obligations as of December 31, 2003. The Company has no off-balance sheet financing arrangements or other similar unrecorded obligations and the Company has not guaranteed the debt of any other party. The following table lists the Company's significant obligations at December 31, 2003:

	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	$ —	$ —	$169,080	$ —	$169,080
Senior subordinated notes	—	—	—	225,000	225,000
Operating leases	1,001	1,849	2,317	2,248	7,415
Transportation commitments	5,693	8,635	5,169	5,452	24,949
Processing commitment	2,640	5,280	5,280	7,920	21,120
Drilling rig obligation	2,995	—	—	—	2,995
Total contractual cash obligations	$12,329	$15,764	$181,846	$240,620	$450,559

7.25% Senior Subordinated Notes

In September 2003, the Company issued $225 million principal amount 7.25% Senior Subordinated Notes (the 7.25% Notes) at par for proceeds of $220 million (net of related offering costs). The 7.25%

Notes are due on September 15, 2013 with interest payable on March 15 and September 15 of each year.

The 7.25% Notes are unsecured senior subordinated obligations that rank junior in right of payment to all of the Company's existing and future secured debt. The indentures contain covenants restricting the ability of the Company to incur additional indebtedness, pay dividends or sell significant assets or subsidiaries. The Company was in compliance with all of these covenants at December 31, 2003.

The proceeds from the issuance of the 7.25% Notes together with proceeds received from the September 2003 issuance of common stock were utilized to retire the $110 million five-year Canadian term loan within the Company's unsecured credit facility and retire the $155 million unsecured senior subordinated credit facility originally established to consummate the Matador Petroleum acquisition in June 2003.

Credit Facility

On March 20, 2001, the Company entered into a $225 million credit facility (the "Global Credit Facility"). The Global Credit Facility was comprised of a $75 million line of credit in the U.S. and a $55 million line of credit in Canada which both had maturity dates of March 20, 2004, and a $95 million five-year term loan in Canada which had a maturity date of March 21, 2006. The borrowing base established to support the $225 million line of credit was initially set at $300 million, which was re-approved as of May 1, 2002. In conjunction with Matador acquisition in June 2003, the Company entered into a "New Global Credit Facility" and the borrowing base and line of credit were increased to $425 million. The terms of the New Global Credit Facility provided for: a $290 million line of credit in the U.S. and a $25 million line of credit in Canada which both now mature on June 27, 2007, and a $110 million five-year term loan in Canada which was to mature on March 21, 2006. The terms of the New Global Credit Facility allow 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.

In September 2003, the $110 million five-year Canadian term loan was repaid and retired upon issuance of the 7.25% Notes. Pursuant to the terms of the New Global Credit Facility, the borrowing base of $425 million was then readjusted to $357.5 million and the line of credit was reduced by $110 million to $315 million. At December 31, 2003, the Company had borrowings outstanding under the New Global Credit Facility totaling $168 million or 47% of the new borrowing base at an average interest rate of 2.8%. The amount available for borrowing under the New Global Credit Facility at December 31, 2003 was $147 million.

Borrowings under the New 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 New 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 New 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 $450 million (adjusted upward by 50% of quarterly net income subsequent to June 30, 2003 and 80% 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 at December 31, 2003.

Senior Subordinated Credit Facility

In connection with the consummation of the Matador Petroleum acquisition in June 2003, the Company entered into an unsecured senior subordinated credit facility (the "Subordinated Facility") with a group of lender banks that also participated in the Company's New Global Credit Facility. The initial interest rate on the $155 million loan was established at 8.5%, but provided for quarterly increases of 0.5%.

In September 2003, the Company repaid this $155 million Subordinated Facility utilizing funds received from the issuance of additional common stock and the 7.25% Notes. The loan origination costs of $3.6 million incurred to establish this facility were expensed in this period.

Other Contractual Obligations

The Company leases its corporate office in Denver, Colorado under the terms of an operating lease, which expires in May 2011. Average yearly payments under the lease are approximately $840,000. The Company's offices in Midland, Texas represents a commitment of $235,000 per year through December 2008, the office lease in Dallas, Texas represents a commitment of approximately $380,000 per year through December 2010 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 2004 through 2008.

The Company has entered into various firm transportation commitments for approximately 90.6 Mmcf of gross gas sales per day as of December 31, 2003. These contracts expire in 2004 through 2012.

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

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. The Company anticipates that the rig will continue drilling through the expiration of this agreement in 2004.

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 2003, the average prices received for gas and oil by the Company were $4.07 per Mcf and $22.89 per barrel, respectively, as compared to $2.19 per Mcf and $16.35 per barrel in 2002 and $3.71 per Mcf and $17.86 per barrel in 2001. The Company's gas prices realized in 2003 and 2001 were impacted by financial instruments entered into by the Company to hedge a portion of the natural gas production. Cash settlements associated with these instruments resulted in a $0.34 per Mcf decrease in the realized gas price for 2003 and a $0.27 per Mcf increase in the realized gas price in 2001. The Company's natural gas prices ultimately realized for 2004 may be impacted by the natural gas hedges entered into by the Company.

APPLICATION OF RECENTLY ISSUED ACCOUNTING STANDARDS ON INTANGIBLE ASSETS

The Emerging Issues Task Force ("EITF") currently is deliberating on EITF No. 03-O, "Whether Mineral Rights Are Tangible or Intangible Assets" and EITF No. 03-S "Application of FASB Statement No. 142, Goodwill and Other Intangible Assets, to Oil and Gas Companies." These proposed statements will determine whether contract-based oil and gas mineral rights are classified as tangible or intangible assets based on the EITF's interpretation of SFAS No. 141 and SFAS No. 142. Historically, the Company has classified all of its contract-based mineral rights within property, plant and equipment and has generally not identified these amounts separately.

If the EITF determines that these mineral rights should be presented as intangible assets, the Company would have to reclassify its contract-based oil and gas mineral rights to intangible assets and make additional disclosures in accordance with SFAS No. 142. The amounts that would be reclassified are as follows:

	December 31,	
	2003	2002
	(In thousands)	
INTANGIBLE ASSETS:		
Proved leasehold acquisition costs	$711,544	$340,058
Unproved leasehold acquisition costs	98,165	62,645
Total leasehold acquisition costs	809,709	402,703
Less: Accumulated depletion	141,000	107,158
Net leasehold acquisition costs	$668,709	$295,545

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

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

COMMODITY PRICE FLUCTUTATIONS

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

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

The Company has natural gas hedges, in the form of costless collars and swaps (including related basis swaps), as follows as of December 31, 2003:

	Natural Gas Collars		Natural Gas Swaps	
Period	**Mmbtu/d**	**Weighted Average Floor/Ceiling**	**Mmbtu/d**	**Weighted Average Swap Price**
First Quarter 2004	162,500	$4.77/7.53	37,500	$5.97
Second Quarter 2004	69,500	$3.80/5.40	55,100	$4.48
Third Quarter 2004	69,500	$3.80/5.40	45,100	$4.48
Fourth Quarter 2004	40,000	$3.91/5.94	15,200	$4.48

In January 2004, the Company entered into several additional natural gas costless collars 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 the April through October 2004 period. These transactions cover approximately 24,500 Mmbtu/d with a weighted average floor/ceiling price of $4.32/$5.44.

INTEREST RATE RISK

At December 31, 2003, the Company had $168.0 million outstanding under the New Global Credit Facility at an average interest rate of 2.8%. 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. As a result, the Company's annual interest cost in 2004 will fluctuate based on short-term interest rates. Assuming no change in the amount outstanding during 2004, 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 New Global Credit Facility approximates the fair value.

At December 31, 2003, the Company also had $225.0 million of 7.25% Senior Subordinated Notes outstanding. These notes were issued on September 16, 2003 and subsequently the market interest rate for financial instruments of comparable quality and term declined to 6.25% Based upon this market interest rate, the fair value of the notes at December 31, 2003 is estimated to be approximately $241 million.

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 2003 and 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 audits. The 2001 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 statements 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 audits 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 audits provide a reasonable basis for our opinion.

In our opinion, the 2003 and 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, 2003 and 2002, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed above, the consolidated financial statements of Tom Brown, Inc. for the year ended December 31, 2001, were audited by other auditors who have ceased operations. As described in Notes 2 and 14 these consolidated financial statements have been revised to include the transitional disclosures required by Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets*, which was adopted by the Company as of January 1, 2002 and Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*, which was adopted by the Company as of January 1, 2003. In our opinion, the disclosures for 2001 in Notes 2 and 14 are appropriate. However, we were not engaged to audit, review, or apply any procedures to the 2001 consolidated financial statements of Tom Brown, Inc. and subsidiaries, other than with respect to such disclosures and, accordingly, we do not express an opinion or any other form of assurance on the 2001 consolidated financial statements taken as a whole.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2003, the Company changed its method of accounting for asset retirement obligations; 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 18, 2004

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. THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEAR ENDED DECEMBER 31, 2001 HAVE BEEN REVISED TO INCLUDE THE TRANSITIONAL DISCLOSURES REQUIRED BY STATEMENT OF FINANCIAL ACCOUNTING STANDARD NO. 142, GOODWILL AND OTHER INTANGIBLE ASSETS AND THE TRANSITIONAL DISCLOSURES REQUIRED BY STATEMENT OF FINANCIAL ACCOUNTING STANDARDS NO. 143, ACCOUNTING FOR ASSET RETIREMENT OBLIGATIONS. THE REPORT OF ARTHUR ANDERSEN LLP PRESENTED BELOW DOES NOT EXTEND TO THESE CHANGES.

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, 2003	December 31, 2002
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 34,256	$ 13,555
Accounts receivable, net of allowance for doubtful accounts	117,073	47,414
Fair value of derivative instruments	1,230	—
Inventories	1,045	1,808
Other	7,772	3,988
Total current assets	161,376	66,765
PROPERTY AND EQUIPMENT, AT COST:		
Gas and oil properties, successful efforts method of accounting	1,563,680	959,807
Gas gathering and processing and other plant	119,592	101,054
Other	44,956	35,930
Total property and equipment	1,728,228	1,096,791
Less: Accumulated depreciation, depletion and amortization	423,661	320,306
Net property and equipment	1,304,567	776,485
OTHER ASSETS:		
Goodwill, net	84,484	—
Deferred loan fees and other assets	18,007	7,702
	$1,568,434	$ 850,952
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 98,248	$ 42,773
Accrued expenses	42,263	21,993
Fair value of derivative instruments	2,301	10,886
Total current liabilities	142,812	75,652
BANK DEBT	169,080	133,172
SENIOR SUBORDINATED NOTES	225,000	—
DEFERRED INCOME TAXES	189,131	73,967
OTHER NON-CURRENT LIABILITIES	29,459	4,543
COMMITMENTS AND CONTINGENCIES (Note 13)		
STOCKHOLDERS' EQUITY:		
Convertible preferred stock, $.10 par value Authorized 2,500,000 shares; none issued	—	—
Common Stock, $.10 par value Authorized 55,000,000 shares; Issued and outstanding 45,669,313 and 39,261,191 shares, respectively	4,567	3,926
Additional paid-in capital	693,414	537,449
Unearned stock compensation	(2,148)	—
Retained earnings	112,415	29,678
Accumulated other comprehensive income (loss)	4,704	(7,435)
Total stockholders' equity	812,952	563,618
	$1,568,434	$ 850,952

See accompanying notes to consolidated financial statements.

TOM BROWN, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2003	2002	2001
	(In thousands, except per share amounts)		
REVENUES:			
Gas, oil and natural gas liquids sales	$387,672	$194,276	$274,031
Gathering and processing	19,912	20,467	23,245
Marketing and trading	37,022	58,899	124,667
Drilling	19,857	14,347	14,828
Gain on sale of properties	—	4,114	10,078
Cash (paid) received on derivatives	—	(2,061)	4,121
Change in derivative fair value	1,913	(345)	(3,224)
Loss on marketable security	—	(600)	—
Interest income and other	1,231	171	1,354
Total revenues	467,607	289,268	449,100
COSTS AND EXPENSES:			
Gas and oil production	41,901	32,151	32,060
Taxes on gas and oil production	33,133	16,621	21,020
Gathering and processing costs	7,303	6,918	10,855
Trading	37,232	53,623	122,776
Drilling operations	16,890	13,763	11,851
Exploration costs	29,459	22,824	34,195
Impairments of leasehold costs	7,824	5,564	5,236
Impairment of gas and oil properties	7,791	—	—
General and administrative	27,294	18,413	22,742
Depreciation, depletion and amortization	111,513	91,307	74,371
Accretion	1,420	—	—
Bad debts	762	5,222	1,043
Interest expense and other	26,402	9,726	7,347
Total costs and expenses	348,924	276,132	343,496
Income before income taxes and cumulative effect of change in accounting principles	118,683	13,136	105,604
Income tax provision			
Current	35	(229)	(1,200)
Deferred	(35,052)	(2,981)	(36,927)
Income before cumulative effect of change in accounting principles	83,666	9,926	67,477
Cumulative effect of change in accounting principles	(929)	(18,103)	2,026
Net income (loss)	$ 82,737	$ (8,177)	$ 69,503
Weighted average number of common shares outstanding:			
Basic	41,260	39,217	38,943
Diluted	42,365	40,327	40,227
Earnings per common share—Basic:			
Income before cumulative effect of change in accounting principles	$ 2.03	$ .25	$ 1.73
Cumulative effect of change in accounting principles	(.02)	(.46)	.05
Net income (loss)	$ 2.01	$ (.21)	$ 1.78
Earnings per common share—Diluted:			
Income before cumulative effect of change in accounting principles	$ 1.97	$ .25	$ 1.68
Cumulative effect of change in accounting principles	(.02)	(.45)	.05
Net income (loss)	$ 1.95	$ (.20)	$ 1.73

See accompanying notes to consolidated financial statements.

TOM BROWN, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Deferred Compensation	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
				(In thousands)			
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
Stock options exercised	308	31	4,863	—	—	—	4,894
Issuance of restricted stock	100	10	2,567	—	(2,577)	—	—
Amortization of restricted stock	—	—	—	—	429	—	429
Issuance of common shares, net of offering costs of $6,580,000	6,000	600	147,320	—	—	—	147,920
Income tax benefit of stock options exercised	—	—	1,085	—	—	—	1,085
Accelerated vesting of options	—	—	130	—	—	—	130
Comprehensive income:							
Translation gain	—	—	—	—	—	7,030	7,030
Change in fair value of derivative hedging instruments (net of tax)	—	—	—	—	—	(24,995)	(24,995)
Settlements of derivative hedging instruments reclassified to income (net of tax)	—	—	—	—	—	30,107	30,107
Unrealized loss on marketable security	—	—	—	—	—	(3)	(3)
Net income	—	—	—	82,737	—	—	82,737
Total comprehensive income							94,876
Balance as of December 31, 2003	45,669	$4,567	$693,414	$112,415	$(2,148)	$ 4,704	$812,952

See accompanying notes to consolidated financial statements.

TOM BROWN, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31, 2003	2002	2001
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 82,737	$ (8,177)	$ 69,503
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	111,513	91,307	74,371
Accretion of abandonment liability	1,420	—	—
Unrealized (gain) loss on derivatives	(1,913)	345	—
Loss on marketable security	—	600	—
Gain on sales of assets	—	(4,114)	(10,078)
Stock compensation	862	—	—
Accelerated vesting of options	—	—	3,897
Dry hole costs	10,343	7,791	15,779
Impairments of leasehold costs	7,824	5,564	5,236
Impairment of gas and oil properties	7,791	—	—
Deferred tax provision	35,052	2,981	36,927
Cumulative effect of changes in accounting principles	929	18,103	—
Changes in operating assets and liabilities, net of the effects from the purchase of Stellarton in 2001 and Matador in 2003:			
(Increase) decrease in accounts receivable	(48,234)	15,966	43,520
Decrease (increase) in inventories	895	(114)	(109)
(Increase) decrease in other current assets	(3,746)	(1,762)	388
Increase (decrease) in accounts payable and accrued expenses	23,646	(5,820)	(28,597)
Decrease (increase) in other assets, net	8,186	(1,108)	(2,937)
Net cash provided by operating activities	237,305	121,562	207,900
CASH FLOWS FROM INVESTING ACTIVITIES:			
Proceeds from sales of assets	15,667	10,781	52,366
Capital and exploration expenditures	(249,230)	(146,681)	(244,663)
Changes in accounts payable and accrued expenses for capital expenditures	16,991	(1,271)	(7,082)
Cash paid for Matador stock and options	(267,473)	—	—
Transaction costs for the Matador acquisition	(4,085)	—	—
Payments on non-compete agreements	(2,991)	—	—
Cash acquired in Matador acquisition	3,596	—	—
Acquisition of Stellarton stock	—	—	(74,500)
Direct costs of Stellarton acquisition	—	—	(3,107)
Net cash used in investing activities	(487,525)	(137,171)	(276,986)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings of long-term bank debt	438,000	36,183	109,812
Repayments of long-term bank debt	(532,279)	(24,369)	(54,000)
Proceeds from issuance of subordinated notes	225,000	—	—
Issuance costs of subordinated notes	(5,019)	—	—
Proceeds from issuance of common stock	154,500	—	—
Issuance costs of common stock	(6,580)	—	—
Deferred loan fees	(7,052)	—	—
Proceeds from exercise of stock options	4,171	2,158	11,163
Net cash provided by financing activities	270,741	13,972	66,975
Effect of exchange rate changes on cash balances	180	(4)	(227)
NET CHANGE IN CASH AND CASH EQUIVALENTS	20,701	(1,641)	(2,338)
CASH AND EQUIVALENTS AT BEGINNING OF YEAR	13,555	15,196	17,534
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 34,256	$ 13,555	$ 15,196
Supplemental disclosures of cash flow information:			
Cash paid during the year for:			
Interest	$ 13,805	$ 5,662	$ 7,219
Income taxes	586	1,084	7,421
Refund received of income tax deposit	—	6,000	—
Supplemental schedule of non-cash investing and financing activities:			
Debt assumed in Stellarton Acquisition	$ —	$ —	$ 16,800
Debt assumed in Matador Acquisition	114,480	—	—

See accompanying notes to consolidated financial statements.

TOM BROWN, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
For the Years Ended December 31, 2003, 2002 and 2001

(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. In June 2003, the Company completed its acquisition of Matador Petroleum Corporation ("Matador"). Matador was an exploration and production company active primarily in the East Texas Basin and Permian Basin of New Mexico and West Texas. The gas and oil properties acquired in the Matador transaction complemented the existing operational focus areas of the Company.

Substantially all of the Company's production is sold under market-sensitive contracts. The Company's revenue, profitability and future rate of growth are substantially dependent upon the price of, and demand for, oil, natural gas and natural gas liquids. Prices for natural gas, crude oil and natural gas liquids are subject to wide fluctuation in response to relatively minor changes in their supply and demand as well as market uncertainty and a variety of additional factors that are beyond the control of the Company. These factors include the level of consumer product demand, weather conditions, domestic and foreign governmental regulations, the price and availability of alternative fuels, political conditions in foreign countries, the foreign supply of natural gas and oil and the price of foreign imports and overall economic conditions. The Company is affected more by fluctuations in natural gas prices than oil prices because a majority of its production (84 percent in 2003 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. All significant intercompany accounts and transactions have been eliminated. Certain reclassifications have been made to amounts reported in previous years to conform to the 2003 presentation.

Inventories

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

Property and Equipment

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

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

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

The Company reviews its gas and oil properties for impairment whenever events and circumstances indicate a decline in the recoverability of their carrying value. The Company estimates the expected future cash flows of its gas and oil properties and compares such future cash flows to the carrying amount of the gas and oil properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will adjust the carrying amount of the oil and gas properties to fair value. The factors used to determine fair value include estimates of proved reserves, future commodity prices, future production estimates, anticipated capital expenditures, and a discount rate commensurate with the risk associated with realizing the expected cash flows projected. There were no impairments of producing gas and oil properties in 2002 or 2001. In 2003, an impairment of $7.8 million ($4.9 million after tax) was recognized to reduce the carrying amount associated with certain of the Company's gas and oil properties within the James Lime play in East Texas. After this 2003 impairment, the carrying amount of these properties was reduced to their estimated fair value of $4.1 million.

The provision for depreciation, depletion and amortization of oil and gas properties is calculated on a field-by-field basis using the unit-of-production method.

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, 2003 and 2002, 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. Income and expense items are translated at average exchange rates during the year. Translation gains and losses, including gains or losses on intercompany advances that are of a long-term-investment nature, are deferred as a component of other comprehensive income (loss). As a result of the change in the Canadian dollar relative to the U.S. dollar, the Company reported an unrealized translation gain of $7 million in 2003 and unrealized 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 from time to time enters into non-speculative hedging transactions, including, commodity swap agreements, costless collar agreements, forward sale contracts, commodity futures, options and other similar agreements relating to natural gas and crude oil expected to be produced.

The Company follows the guidance in Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities" in accounting for its 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. SFAS 133 requires that a company formally document, designate, and assess the effectiveness of transactions that receive hedge accounting treatment.

Special accounting for qualifying hedges provides that the gains and losses on a derivative be accounted for as an offset to the related results on the hedged item in the income statement. SFAS 133, provides that for cash flow hedges, 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 is reclassified into earnings in the same period or periods during which the hedged forecasted transaction affects earnings.

Recently Issued Accounting Standards

In June 2001, the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets," which addresses, among other things, the financial accounting and reporting for goodwill subsequent to an acquisition. The new standard eliminates the requirement to amortize acquired goodwill; instead, such goodwill is reviewed at least annually for impairment. The Company adopted SFAS No. 142 on January 1, 2002, designating its reporting units as (i) gas and oil exploration and development in the United States, (ii) gas and oil exploration and development in Canada, (iii) marketing, gathering and processing and (iv) drilling. The first two reporting units are included in the gas and oil exploration and development segment. A fair value based test was conducted effective January 1, 2002 to evaluate the goodwill originally recorded in conjunction with the January 2001 Stellarton Energy Corporation acquisition. The fair value of the reporting unit was determined with reference to the estimated discounted future net revenues of the underlying gas and oil reserves as of the date of the test and other financial considerations, including going-concern value. This test resulted in the Company recording a non-cash charge of $18.1 million in the quarter ended March 31, 2002. This expense has been reflected in the consolidated statements of operations as a cumulative effect of a change in accounting principle. In conjunction with the Company's acquisition of Matador on June 27, 2003, the Company recorded goodwill of $84.5 million The Company tests its goodwill for impairment on December 31 of each year.

Had SFAS No. 142 been effective for the year ended December 31, 2001, the Company's net income would have been as follows (in thousands, except per share amounts):

	Year Ended December 31, 2001
Net income	
As reported	$69,503
Amortization of goodwill (net of tax effect)	563
Pro forma	$70,066
Basic net income per common share:	
As reported	$ 1.78
Pro forma	$ 1.80
Diluted net income per common share:	
As reported	$ 1.73
Pro forma	$ 1.74

Proposed Accounting Standards

The Emerging Issues Task Force ("EITF") currently is deliberating on EITF No. 03-O, "Whether Mineral Rights Are Tangible or Intangible Assets" and EITF No. 03-S "Application of FASB Statement No. 142, Goodwill and Other Intangible Assets, to Oil and Gas Companies." These proposed statements will determine whether contract-based oil and gas mineral rights are classified as tangible or intangible assets based on the EITF's interpretation of SFAS No. 141 and SFAS No. 142. Historically, the Company has classified all of its contract-based mineral rights within property, plant and equipment and has generally not identified these amounts separately.

If the EITF determines that these mineral rights should be presented as intangible assets, the Company would have to reclassify its contract-based oil and gas mineral rights to intangible assets and make additional disclosures in accordance with SFAS No. 142. The amounts that would be reclassified are as follows:

	December 31,	
	2003	2002
	(In thousands)	
INTANGIBLE ASSETS:		
Proved leasehold acquisition costs	$711,544	$340,058
Unproved leasehold acquisition costs	98,165	62,645
Total leasehold acquisition costs	809,709	402,703
Less: Accumulated depletion	141,000	107,158
Net leasehold acquisition costs	$668,709	$295,545

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

In July 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations". SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted each period toward its future value, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity reports a gain or loss upon settlement to the extent the actual costs differ from the recorded liability. The Company adopted SFAS No. 143 on January 1, 2003 and recorded a discounted liability of $14.5 million for the future retirement obligation, increased net property and equipment by $13.0 million and recorded 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 recognized related 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 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. 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 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 October 2002, the Emerging Issues Task Force reached a consensus on EITF Issue No. 02-03, *Recognition and Reporting of Gains and Losses on Energy Trading Contracts.* The consensus rescinded EITF Issue No. 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities.* Under the consensus, effective January 1, 2003, all energy related contracts that qualify as derivatives under *Statement of Financial Accounting Standards No. 133* are required to be recorded at fair value and the purchase and sale amounts are reported net in the statement of income. All other contracts are accounted for as executory contracts using the accrual method of accounting and the purchase and sales amounts are reported gross in the statement of income. The contracts entered into in connection with the Company's marketing and trading activities do not qualify as derivatives, and as a result continue to be reported on a gross basis in the statement of income. Prior period financial statements were reclassified to present these purchase and sales amounts on a gross basis. The reclassifications did not impact the reported marketing and trading margins, or the amount of reported net income.

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 adoption of this statement did not impact the Company's financial position or results of operations because the Company has not adopted the fair value method of accounting for stock-based compensation.

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 is recognized for grants of options at the market price under the Company's stock option plans unless there is a modification to the original terms of the option grant.

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 ($2.4 million after tax) was recognized in 2001.

In 2003, an individual retired from the Company's Board of Directors and as a result of an earlier revision to the terms of an option grant, the retiring director received an extension of time to exercise the outstanding options. This modification established a new measurement date and a non-cash pre-tax charge to earnings of $.4 million ($.3 million after tax) was recognized in 2003.

If compensation costs for 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,		
	2003	2002	2001
	(In thousands, except per share amounts)		
Net income (loss)			
As reported	$82,737	$ (8,177)	$69,503
Add: Compensation cost included in reported net income (loss) (net of tax)	273	—	2,361
Deduct: Stock-based employee compensation expense determined under fair value based method for all awards (net of tax)	(6,744)	(5,090)	(5,294)
Pro forma	$76,266	$(13,267)	$66,570
Basic net income (loss) per common share:			
As reported	$ 2.01	$ (.21)	$ 1.78
Pro forma	$ 1.85	$ (.34)	$ 1.71
Diluted net income (loss) per common share:			
As reported	$ 1.95	$ (.20)	$ 1.73
Pro forma	$ 1.80	$ (.33)	$ 1.65

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires 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.

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, 2003, 2002 and 2001:

	2003			2002			2001		
	Net Income	Shares	Per Share Amount	Net Loss	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
Basic EPS:									
Net Income (Loss) and Share Amounts	$82,737	41,260	$2.01	$(8,177)	39,217	$(.21)	$69,503	38,943	$1.78
Dilutive Securities:									
Stock Options	—	1,105	(.06)	—	1,110	.01	—	1,284	(.05)
Diluted EPS:									
Net Income (Loss) and Diluted Share Amounts	$82,737	42,365	1.95	$(8,177)	40,327	$(.20)	$69,503	40,227	$1.73

Options to purchase 956,000, 1,688,000 and 1,180,000 shares of common stock in 2003, 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.

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, 2003, 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, unrealized foreign currency translation gains and losses, and unrealized gains and losses on derivative instruments.

(3) Acquisitions and Divestitures

Acquisition of Matador

On June 27, 2003, the Company completed its acquisition of Matador, a Texas corporation. Matador was an exploration and production company active primarily in the East Texas Basin and Permian Basin of Southeastern New Mexico and West Texas. The acquisition increased Tom Brown's proved reserves by an estimated 269 billion cubic feet equivalent (Bcfe) (unaudited).

Under the terms of the definitive merger agreement, the Matador shareholders received a net price of $17.53 per common share and all option holders received $17.53 per option share less the exercise price of the options. Tom Brown also assumed approximately $121 million in net debt at closing for an aggregate purchase price, including transactional fees, of $388 million. Transaction costs of approximately $6.0 million were incurred for investment banking, legal, accounting and other direct merger-related costs. In addition, $7.7 million was incurred for payments made to officers and employees of Matador pursuant to a change in control arrangement previously entered into by Matador and $1.3 million was incurred for payments made to Matador employees under the terms of a stock appreciation plan, which provided for payments in the event of a change in control of Matador.

The allocation of the purchase price to the Matador assets resulted in a difference between the book and tax basis of the Matador assets of approximately $214 million. Based upon an effective tax rate of 35 percent, deferred income taxes of $71.8 million were recorded. The deferred taxes recorded represent the majority of the $84.5 million of goodwill recorded in conjunction with the acquisition.

The other non-current liability of Matador that was assumed principally represents the asset retirement obligation accounted for SFAS No. 143. The asset retirement obligation related to the Matador assets at June 30, 2003 was $4.8 million.

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

Acquisition costs:	
Cash paid to stock and option holders	$ 267,473
Long-term debt assumed	114,480
Other non-current liabilities assumed	5,733
Direct transaction costs incurred by the Company	800
Total consideration	388,486
Allocation of acquisition costs:	
Oil and gas properties—proved	(360,000)
Unproved properties	(25,000)
Other property and equipment	(1,185)
Cash acquired in the transaction	3,596
Deferred income taxes	71,785
Net working capital deficit	6,802
Goodwill	$ 84,484

Pro Forma Results of Operations (Unaudited)

The following table reflects the unaudited pro forma results of operations for the years ended December 31, 2003 and 2002 as though the Matador 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, 2003	2002
	(In thousands, except per share data)	
Revenues	$526,440	$ 95,849
Net income (loss)	$ 91,106	$(18,181)
Basic net income (loss) per share	$ 2.21	$ (.45)
Diluted net income (loss) per share	$ 2.15	$ (.45)

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 No. 142, "Goodwill and Other Intangible Assets" and wrote off 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):

Acquisition costs:	
Purchase price financed by long-term debt	$ 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.

Acquisition of Rocky Mountain Assets

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

Property Sales

In December 2003, the Company sold its' interest in gas and oil properties located in the Permian Basin of Texas to an unrelated third party for net cash proceeds of $12.9 million. The resulting gain was not significant.

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

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

In 2001, $52.4 million in cash proceeds were derived from property sales. In May 2001, the Company sold its interest in gas and oil properties located in Oklahoma to an unrelated third party. These properties had a net book basis of $14.4 million. This transaction resulted in a pretax 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. 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.

(4) Debt

7.25% Senior Subordinated Notes

In September 2003, the Company issued $225 million principal amount of 7.25% Senior Subordinated Notes (the 7.25% Notes) at par for proceeds of $220 million (net of related offering costs). The 7.25% Notes are due on September 15, 2013 with interest payable on March 15 and September 15 of each year.

The 7.25% Notes are unsecured senior subordinated obligations that will rank junior in right of payment to all of the Company's existing and future secured debt. The indentures contain covenants restricting the ability of the Company to incur additional indebtedness, pay dividends or sell significant assets or subsidiaries. The Company was in compliance with all of these covenants at December 31, 2003.

The proceeds from the issuance of the 7.25% Notes and proceeds received from the September 2003 issuance of common stock were utilized to retire the $110 million five-year Canadian term loan within the Company's unsecured credit facility and retire the $155 million unsecured senior subordinated credit facility originally established to consummate the Matador Petroleum acquisition in June, 2003.

Credit Facility

On March 20, 2001, the Company entered into a $225 million credit facility (the "Global Credit Facility"). The Global Credit Facility was comprised of: a $75 million line of credit in the U.S. and a $55 million line of credit in Canada which both had maturity dates of March 20, 2004, and a $95 million five-year term loan in Canada which had a maturity date of March 21, 2006. The borrowing base established to support the $225 million line of credit was initially set at $300 million, which was re-approved as of May 1, 2002. In conjunction with Matador acquisition in June 2003, the Company entered into a "New Global Credit Facility" and the borrowing base and line of credit were increased to $425 million. The terms of the New Global Credit Facility provided for: a $290 million line of credit in the U.S. and a $25 million line of credit in Canada which both now mature on June 27, 2007 and a $110 million five-year term loan in Canada which was to mature on March 21, 2006. The terms of the New Global Credit Facility allow 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.

In September 2003, the $110 million five-year Canadian term loan was repaid and retired upon issuance of the 7.25% Notes. Pursuant to the terms of the New Global Credit Facility, the borrowing base of $425 million was then readjusted to $357.5 million and the line of credit was reduced by $110 million to $315 million. At December 31, 2003, the Company had borrowings outstanding under the New Global Credit Facility totaling $168 million or 47% of the new borrowing base at an average interest rate of 2.8%. The amount available for borrowing under the New Global Credit Facility at December 31, 2003 was $147 million.

Borrowings under the New 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 New 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 New 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 $450 million (adjusted upward by 50% of quarterly net income subsequent to June 30, 2003 and 80% 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 at December 31, 2003.

Senior Subordinated Credit Facility

In connection with the consummation of the Matador Petroleum acquisition in June 2003, the Company entered into an unsecured senior subordinated credit facility (the "Subordinated Facility") with a group of lender banks that also participated in the Company's New Global Credit Facility. The initial interest rate on the $155 million loan was established at 8.5%, but provided for quarterly increases of 0.5%.

In September 2003, the Company repaid this $155 million Subordinated Facility utilizing funds received from the issuance of additional common stock and issuance of the 7.25% Notes. The loan origination costs of $3.6 million incurred to establish this facility were expensed in this period.

(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:

	Years Ended December 31,		
	2003	2002	2001
	(In thousands)		
Tax expense at 35% of income before income taxes and change in accounting principles	$(41,539)	$(4,598)	$(36,961)
State tax expense net of federal benefit	(2,374)	(263)	(2,112)
Alternative minimum tax and other taxes	(991)	(614)	(486)
Canadian Crown payments (net of Alberta Royalty Tax Credit) not deductible for tax purposes	(4,010)	(2,879)	(4,136)
Canadian resource allowance	3,836	2,699	3,556
Canadian expenses deductible in the United States	2,330	1,578	1,845
Canadian Large Corporation Tax	(394)	(285)	(335)
Adjustments to prior periods due to filed returns	127	397	502
Canadian tax rate reduction	6,465	—	—
Enterprise zone tax credits	—	1,018	—
Canadian tax refund from prior tax year	1,420	—	—
Other	113	(263)	—
Total income tax expense	$(35,017)	$(3,210)	$(38,127)

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.

The components of the net deferred tax liability by geographical segment at December 31, 2003 and 2002 were as follows:

	December 31, 2003		
	United States	Canada	Total
	(In thousands)		
Deferred tax assets:			
Net operating loss carryforward	$ 21,349	$ —	$ 21,349
Percentage depletion carryforward	2,534	—	2,534
Alternative minimum tax credit carryforward	5,222	—	5,222
Other	1,837	—	1,837
Total gross deferred tax assets	30,942	—	30,942
Deferred tax liabilities:			
Property and equipment	(182,291)	(37,347)	(219,638)
Other	(435)	—	(435)
Total gross deferred tax liabilities	(182,726)	(37,347)	(220,073)
Net deferred tax liabilities	$(151,784)	$(37,347)	$(189,131)

	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)

The Alternative Minimum Tax (AMT) credit carryforward available to reduce future U.S. Federal regular taxes aggregated $5.2 million at December 31, 2003. This amount may be carried forward indefinitely. U.S. Federal regular and AMT net operating loss carryforwards at December 31, 2003 were approximately $58.0 and $50.0 million, respectively, and will expire in 2020. 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, 2003. This amount may be carried forward indefinitely.

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 $66.0 million ($91.8 million CDN) at December 31, 2003. 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.

The allocation of the purchase price to the Matador assets resulted in a difference between the book and tax basis of the Matador assets of approximately $214 million. Based upon an effective tax rate of 35 percent, deferred income taxes of $71.8 million were recorded.

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. Due to an income tax rate reduction in Canada during 2003, an adjustment to reduce the deferred tax liability by $6.5 million ($9.3 million CDN) has been recorded at December 31, 2003.

(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,		
	2003	2002	2001
	(In thousands)		
Revenues	$37,276	$55,162	$123,767
Operating expenses	37,232	53,623	122,776
Net trading margin	44	1,539	991
Marketing margin on the Company's production	(254)	3,737	900
Marketing and trading revenues—net	$ (210)	$ 5,276	$ 1,891

(7) Stockholders' Equity

Preferred Stock

The Company's Convertible Preferred Stock is $.10 par value per share. There were 2,500,000 authorized shares of Preferred Stock at December 31, 2003. No preferred shares were outstanding at December 31, 2003 and 2002.

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, 2003 of which 45,669,313 shares and 39,261,191 shares were outstanding at December 31, 2003 and 2002, 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 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.

(8) Benefit Plans

1989 Plan

The Company's 1989 Stock Option Plan (the "1989 Plan") expired in December 1999. As of December 31, 2003, options to purchase 250,500 shares of the Company's common stock were outstanding under the 1989 Plan. These options will expire between 2004 and 2008 if not previously exercised.

1993 Plan

The Company's 1993 Stock Option Plan (the "1993 Plan") expired in February 2003. Options to purchase 2,615,800 shares of the Company's Common Stock were outstanding under this plan as of December 31, 2003.

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 30,500, 447,400, and 378,700 shares of the Company's Common Stock in 2003, 2002, and 2001, respectively. In 2003, restricted stock awards of 100,200 shares were also granted. 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 1,176,300 shares of the Company's Common Stock were outstanding under the 1999 Plan as of December 31, 2003.

2003 Plan

In February 2003, the Board of Directors adopted the Company's 2003 Stock Option Plan (the "2003 Plan") which was approved by the stockholders on May 8, 2003. The 2003 Plan provides for issuance of options to employees and directors to purchase shares of Common Stock. The aggregate number of shares of Common Stock that may be issued under the 2003 plan is 1,800,000 shares. The exercise price, vesting and duration of the options may vary and will be determined at the time of issuance. There were option grants made to purchase 1,146,750 shares of the Company's Common Stock in 2003. Options to purchase 1,117,600 shares of the Company's Common Stock were outstanding under this plan as of December 31, 2003.

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,					
	2003		2002		2001	
	Shares Under Option	Weighted Average Exercise Price	Shares Under Option	Weighted Average Exercise Price	Shares Under Option	Weighted Average Exercise Price
Outstanding, beginning of year	4,313	$20.81	3,919	$19.60	3,412	$14.52
Granted	1,242	26.31	700	26.61	1,531	29.56
Exercised	(287)	14.56	(152)	13.63	(778)	14.50
Cancellations	(108)	24.87	(154)	23.44	(246)	26.45
Outstanding, end of year	5,160	22.40	4,313	20.81	3,919	19.60
Exercisable, end of year	2,499	19.04	1,941	16.92	1,331	14.24
Available for grant, end of year	1,351		759		1,305	

The weighted average fair value of options granted during the years ended December 31, 2003, 2002, and 2001 was $23.72, $24.33, and $18.12, 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 2003, 2002, and 2001, respectively: (i) risk-free interest rates of 3.77, 3.47, and 4.46 percent; (ii) expected lives of 7.0, 7.0 and 7.0 years, (iii) expected volatility of 120.0, 126.0, and 56.0 percent, and (iv) no dividend yields.

The following table summarizes information about stock options outstanding at December 31, 2003:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	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)			
$8.6250 to $12.6875	565	5.18	$12.44	442	$12.40
$12.7500 to $13.8750	563	3.31	13.50	427	13.52
$13.9375 to $15.2500	162	3.68	14.92	153	14.95
$15.6875 to $15.6875	528	4.10	15.69	528	15.69
$16.0625 to $24.5000	574	7.30	21.88	295	21.22
$24.7000 to $25.1000	114	9.33	24.99	3	24.88
$25.1100 to $25.9000	537	9.25	25.86	15	25.50
$25.9300 to $26.8800	612	8.30	26.83	139	26.86
$26.9000 to $27.6200	524	9.32	27.25	17	27.37
$27.6700 to $34.0000	981	7.23	30.81	480	30.89
	5,160	6.75	22.40	2,499	19.04

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 in 2001.

In 2003, an individual retired from the Company's Board of Directors and as a result of an earlier revision to the terms of an option grant, the retiring director received an extension of time to exercise the outstanding options. This modification established a new measurement date and a non-cash pre-tax charge to earnings of $.4 million ($.3 million after tax) was recognized in 2003.

Employee Benefit Plans

Effective January 1, 2000, the Company adopted a 401(k) retirement plan. The Company has the discretion to match employee contributions to the plan. As of December 31, 2003, the Company's policy was to match 100% of the employee contribution up to seven percent of the employee's salary. The employer contributions for the years ended December 31, 2003, 2002 and 2001, was approximately $1,577,000, $1,403,000 and $864,000, 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 the bank debt approximated fair value because the interest rate is variable and is reflective of current market conditions. At December 31, 2003, the Company also had $225 million of 7.25% Senior Subordinated Notes outstanding. These notes were issued on September 16, 2003 and subsequently the market interest rate for financial instruments of comparable quality and term declined to 6.25%. Based upon this market interest rate, the fair value of the notes at December 31, 2003 is estimated to be approximately $241 million.

Derivative Instruments and Hedging Activities

The Company periodically enters into natural gas and crude oil futures contracts with counterparties 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, 2003 the Company had a current derivative liability of $2.3 million, a deferred tax asset of $.9 million and accumulated other comprehensive loss of approximately $1.4 million. At December 31, 2002, the Company had a current derivative liability of $10.9 million, a deferred tax asset of $4.0 million and accumulated other comprehensive loss of approximately $6.5 million.

In anticipation of the Matador acquisition, the Company entered into several new natural gas costless collars (put and call options) in May 2003 that were based on separate regional price indexes. These contracts were based upon the areas that Matador physically delivered its natural gas and related to production from June 2003 to December 2004. A derivative gain of $1.9 million was recognized on the change in the fair value of these instruments prior to the completion of the Matador acquisition when these contracts were re-designated as hedges of future production. At December 31, 2003, the Company had a net current derivative asset of $1.2 million to be amortized against future production associated with this re-designation.

In October and December 2003, the Company entered into several additional natural gas 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 January through March 2004. In December 2003, the Company entered into several natural gas price swaps and corresponding basis swaps transactions that together fixed the price the Company will receive for a portion of its natural gas production. These swaps were designated as hedges of production from January through October 2004 in certain of the regions where the Company physically delivers its gas.

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, 2003:

	Natural Gas Collars		Natural Gas Swaps	
Period	Mmbtu/d	Weighted Average Floor/Ceiling	Mmbtu/d	Weighted Average Swap Price
First Quarter 2004	162,500	$4.77/7.53	37,500	$5.97
Second Quarter 2004	69,500	$3.80/5.40	55,100	$4.48
Third Quarter 2004	69,500	$3.80/5.40	45,100	$4.48
Fourth Quarter 2004	40,000	$3.91/5.94	15,200	$4.48

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.

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 which were reported directly in earnings. As of December 31, 2002, the Company recognized derivative losses of $2.1 million on these contracts all of which were settled in 2002.

The Company recognized a decrease in gas and oil sales of $27.7 million in 2003 as a result of cash flow hedges. In 2002, cash flow hedges had no impact on gas and oil sales. The Company recognized an increase in gas and oil sales of $17.4 million in 2001 as a result of cash flow hedges. 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, Mr. James B. Wallace, participates, both directly as an individual holding minor interests in six producing wells and indirectly through a partnership, with the Company and other unrelated investors in the drilling, development and operation of gas and oil properties. During the years ended December 31, 2003, 2002, and 2001, the Company billed $11,000, $111,000 and $621,000, respectively, to this partnership for its share of certain leasehold and drilling costs. 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 $37,000, $38,000, and $41,000 during the years ended December 31, 2003, 2002 and 2001, respectively, to a consulting firm of Groppe, Long & Littell of which Mr. Henry Groppe, a director of the Company, is a partner.

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

No one purchaser accounted for 10% or more of the Company's total gas and oil revenue during 2003. Because there are numerous other parties available to purchase the Company's production, the Company does not believe that the loss of a major purchaser would 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. As discussed in the preceding paragraph, the Company did not have a significant customer that accounted for 10% or more of the Company's total gas and oil revenue during 2003. However, as described in the following paragraph, the Company did have a purchaser default on payments owed the Company, in 2002, totaling $6.2 million. The Company does attempt to obtain credit protections such as letters of credit, guarantees and prepayments from certain of its purchasers.

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.

(11) Allowance for Doubtful Accounts

The allowances for doubtful accounts is recorded as a reduction of accounts receivable in the Consolidated Balance Sheets. Changes in the allowance for doubtful accounts are as follows (in thousands):

	Years Ended December 31,		
	2003	2002	2001
Balance January 1	$ 978	$ 710	$461
Charged to bad debt expense	762	5,222	175
Acquisition of Stellarton	—	—	168
Accounts receivable written off	—	(4,954)	(94)
Balance December 31	$1,740	$ 978	$710

(12) 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.

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

	As of or Year Ended December 31, 2003					
	Gas & Oil Exploration & Development (United States)	Gas & Oil Exploration & Development (Canada)	Gas & Oil Exploration & Development (Total)	Marketing, Gathering & Processing	Drilling	Total Segments
Revenues						
Revenues from external purchasers	$ 225,745	$ 41,396	$ 267,141	$284,411	$19,857	$ 571,409
Intersegment revenues	120,530	—	120,530	10,120	7,895	138,545
Total revenues	346,275	41,396	387,671	294,531	27,752	709,954
Marketing and trading expenses offset against related revenues for net presentation	—	—	—	(106,947)	—	(106,947)
Intersegment eliminations	—	—	—	(130,650)	(7,895)	(138.545)
Total segment revenue	346,275	41,396	387,671	56,934	19,857	464,462
Gain on sale of property	330	—	330	—	—	330
Change in derivative fair value	1,913	—	1,913	—	—	1,913
Interest income and other	215	38	253	442	207	902
Total consolidated revenues	$ 348,733	$ 41,434	$ 390,167	$ 57,376	$20,064	$ 467,607
Profit						
Total reportable segment profit	$ 124,409	$ 11,730	$ 136,139	$ 8,513	$ 2,211	$ 146,863
Interest expense and other	(19,443)	(6,634)	(26,077)	5	—	(26,072)
Eliminations	—	—	—	—	(2,108)	(2,108)
Income before income taxes and cumulative effect of change in accounting principle	$ 104,966	$ 5,096	$ 110,062	$ 8,518	$ 103	$ 118,683
Depreciation, depletion and amortization	$ 92,017	$ 15,200	$ 107,217	$ 2,487	$ 1,809	$ 111,513
Assets						
Total reportable segment assets	$1,371,854	$198,959	$1,570,813	$ 81,537	$22,827	$1,675,175
Intersegment eliminations	(41,365)	(36,713)	(78,078)	(25,194)	(3,471)	(106,743)
Total consolidated assets	$1,330,489	$162,246	$1,492,735	$ 56,343	$19,356	$1,568,434
Capital and exploration expenditures	$ 608,911	$ 30,738	$ 639,649	$ 13,853	$ 4,867	$ 658,369

	As of or Year Ended December 31, 2002					
	Gas & Oil Exploration & Development (United States)	Gas & Oil Exploration & Development (Canada)	Gas & Oil Exploration & Development (Total)	Marketing, Gathering & Processing	Drilling	Total Segments
Revenues						
Revenues from external purchasers	$114,039	$ 27,774	$141,813	$180,842	$14,347	$337,002
Intersegment revenues	52,463	—	52,463	11,625	6,774	70,862
Total revenues	166,502	27,774	194,276	192,467	21,121	407,864
Marketing and trading expenses offset against related revenues for net presentation	—	—	—	(49,013)	—	(49,013)
Intersegment eliminations	—	—	—	(64,088)	(6,774)	(70,862)
Total segment revenue	166,502	27,774	194,276	79,366	14,347	287,989
Cash paid on derivatives	—	—	—	(2,061)	—	(2,061)
Gain on sale of property	4,114	—	4,114	—	—	4,114
Loss on marketable security	(600)	—	(600)	—	—	(600)
Change in derivative fair value	(345)	—	(345)	—	—	(345)
Interest income and other	70	37	107	20	44	171
Total consolidated revenues	$169,741	$ 27,811	$197,552	$ 77,305	$14,391	$289,268
Profit						
Total reportable segment profit	$ 4,314	$ 4,222	$ 8,536	$ 12,598	$ 308	$ 21,442
Interest expense and other	(4,349)	(5,054)	(9,403)	3	(326)	(9,726)
Gain on sale of property	4,114	—	4,114	—	—	4,114
Loss on marketable security	(600)	—	(600)	—	—	(600)
Eliminations	—	—	—	—	(2,094)	(2,094)
Income before income taxes and cumulative effect of change in accounting principle	$ 3,479	$ (832)	$ 2,647	$ 12,601	$(2,112)	$ 13,136
Depreciation, depletion and amortization	$ 72,788	$ 14,499	$ 87,287	$ 2,594	$ 1,426	$ 91,307
Assets						
Total reportable segment assets	$667,446	$149,589	$817,035	$ 67,422	$16,376	$900,833
Intersegment eliminations	(917)	(27,773)	(28,690)	(20,084)	(1,107)	(49,881)
Total consolidated assets	$666,529	$121,816	$788,345	$ 47,338	$15,269	$850,952
Capital and exploration expenditures	$144,882	$ 13,278	$158,160	$ 4,705	$ 943	$163,808

The following tables reconcile segment information to consolidated totals:

	As of or Year Ended December 31, 2001					
	Gas & Oil Exploration & Development (United States)	Gas & Oil Exploration & Development (Canada)	Gas & Oil Exploration & Development (Total)	Marketing, Gathering & Processing	Drilling	Total Segments
Revenues:						
Revenues from external purchasers	$173,422	$ 30,133	$203,555	$266,386	$14,828	$484,769
Intersegment revenues	70,476	—	70,476	6,556	12,777	89,809
Total revenues	243,898	30,133	274,031	272,942	27,605	574,578
Marketing and trading expenses offset against related revenues for net presentation	—	—	—	(47,998)	—	(47,998)
Intersegment eliminations	—	—	—	(77,032)	(12,777)	(89,809)
Total segment revenue	243,898	30,133	274,031	147,912	14,828	436,771
Cash paid on derivatives	—	—	—	4,121	—	4,121
Gain on sale of property	10,078	—	10,078	—	—	10,078
Change in derivative fair value	(3,224)	—	(3,224)	—	—	(3,224)
Interest income and other	1,369	(237)	1,132	137	85	1,354
Total consolidated revenues	$252,121	$ 29,896	$282,017	$152,170	$14,913	$449,100
Profit						
Total reportable segment profit	$ 85,932	$ 5,593	$ 91,525	$ 9,671	$ 5,141	$106,337
Interest expense and other	713	(5,998)	(5,285)	—	(854)	(6,139)
Gain on sale of property	10,078	—	10,078	—	—	10,078
Eliminations	—	—	—	—	(4,672)	(4,672)
Income before income taxes and cumulative effect of change in accounting principle	$ 96,723	$ (405)	$ 96,318	$ 9,671	$ (385)	$105,604
Depreciation, depletion and amortization	$ 55,692	$ 14,079	$ 69,771	$ 2,951	$ 1,649	$ 74,371
Assets						
Total reportable segment assets	$644,483	$165,399	$809,882	$ 59,333	$19,606	$888,821
Intersegment eliminations	5,257	(23,115)	(17,858)	(22,168)	(3,820)	(43,846)
Total consolidated assets	$649,740	$142,284	$792,024	$ 37,165	$15,786	$844,975
Capital and exploration expenditures	$316,934	$ 31,280	$348,214	$ 9,300	$ 5,237	$362,751

(13) 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 was 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 was one of more than a dozen virtually identical class action lawsuits filed in various Wyoming courts against producers and operators in Wyoming. The complaint alleged 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 was 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. Pending the resolution of these issues by the Wyoming Supreme Court, the Company elected to settle the alleged violations under the Act and effective September 30, 2003 for a settlement amount of $4.2 million. The settlement established a future royalty payment methodology to allow the Company a safe harbour to remain in compliance with the Act and provided the Company with the ability to opt out of the methodology when an ultimate decision is reached by the Wyoming Supreme Court as to the deductibility of transportation costs as a production cost.

Lease Commitments

At December 31, 2003, the Company had long-term leases through 2011 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)
2004	$1,001
2005	848
2006	1,001
2007	1,134
2008	1,183
Thereafter	2,248
	$7,415

Total rental expense incurred for the years ended December 31, 2003, 2002 and 2001, was approximately $1,698,000, $1,648,000 and $1,558,000, 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, 2003 for the next five years and thereafter is as follows:

Years Ending December 31,	Commitment Amount
	(In thousands)
2004	$ 5,693
2005	5,085
2006	3,550
2007	3,088
2008	2,081
Thereafter	5,452
	$24,949

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 for compression services made available during the ten-year term of this agreement. 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 approximately $100,000 in 2003 and $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, 2003. Based on the amount of remediation costs estimated for this site and the Company's *de minimis* contribution, if any, the Company believes that any difference between the accrual and the actual costs to be incurred for this site restoration project will not have a material adverse effect on its financial position or results of operations.

(14) Asset Retirement Obligations

Effective January 1, 2003, the Company adopted SFAS 143, "Accounting for Asset Retirement Obligations." SFAS 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement cost is capitalized as part of the carrying amount of the long-lived asset. Subsequently, the asset retirement cost is allocated to expense using a systematic and rational method over the asset's useful life. The adoption of SFAS 143 resulted in an increase of total liabilities as retirement obligations were required to be recognized, the recorded cost of assets increased to include the retirement costs added to the carrying amount of the asset and operating expenses increased subsequent to January 1, 2003 due to the accretion of the retirement obligation. The majority of the asset retirement obligations recorded by the Company relate to the plugging and abandonment of gas and oil wells. Asset retirement obligations were also recorded for processing plants and compressors.

The following is a reconciliation of the Company's asset retirement obligation for the year ended December 31, 2003.

	Year Ended December 31, 2003
	(In thousands)
Asset retirement obligation—beginning of period	$ —
Adoption of SFAS 143	14,475
Obligations acquired	4,844
Obligations incurred	1,790
Obligations settled	(1,121)
Obligations on sold properties	(205)
Accretion expense	1,420
Asset retirement obligation—end of period	$21,203

The following unaudited pro forma information has been prepared to give effect to the adoption of SFAS 143 as if it had been adopted on January 1, 2001.

	Year Ended	
	December 31, 2002	December 31, 2001
	(In thousands, except per share amounts)	
Net (loss) income		
As reported	$(8,177)	$69,503
Accretion of retirement obligations (net of tax)	(675)	(615)
Reduction of depreciation and depletion (net of tax)	447	434
Pro Forma	$(8,405)	$69,322
Basic net income (loss) per common share:		
As reported	$ (.21)	$ 1.78
Pro Forma	$ (.21)	$ 1.78
Diluted net income (loss) per common share:		
As reported	$ (.20)	$ 1.73
Pro Forma	$ (.20)	$ 1.72

(15) Quarterly Financial Data (Unaudited)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(In thousands, except per share amounts)				
Year ended December 31, 2003					
Revenues	$104,038	$97,933	$126,209	$139,427	$467,607
Net income	19,868	21,356	16,012	25,501	82,737
Net income per common share(1)					
Basic	.51	.54	.40	.56	2.01
Diluted	.49	.53	.39	.54	1.95
Year ended December 31, 2002					
Revenues	$ 68,095	$79,519	$ 60,529	$ 81,125	$268,268
Net (loss) income	(18,474)	4,755	(1,831)	7,373	(8,177)
Net (loss) income per common share(1)					
Basic	(.47)	.12	(.05)	.19	(.21)
Diluted	(.47)	.12	(.05)	.18	(.20)

(1) The sum of the individual quarterly net income per share may 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.

(16) 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 (in thousands):

	December 31, 2003	2002	2001
Capitalized costs			
Proved gas and oil properties	$1,478,293	$ 907,006	$ 780,300
Unproved gas and oil properties	85,387	52,801	69,328
Total gas and oil properties	1,563,680	959,807	849,628
Less: Accumulated depreciation, depletion and amortization	(394,185)	(290,983)	(213,297)
Net capitalized costs	$1,169,495	$ 668,824	$ 636,331

	United States	Canada	Total
Costs incurred			
2003			
Proved property acquisition costs	$382,757	$ —	$382,757
Unproved property acquisition costs	32,288	3,110	35,398
Exploration costs	45,298	4,772	50,070
Development and asset retirement costs	149,522	22,286	171,808
Total	$609,865	$ 30,168	$640,033
2002			
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			
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

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.

Estimates of proved and proved developed reserves were prepared by the Company's petroleum engineering staff and reviewed by its independent petroleum engineering consultants. The Company's gas, oil and natural gas liquids reserves are located in the United States and Canada.

Reserves have been classified as proved, proved developed and proved undeveloped pursuant to the following definitions:

Proved gas and oil reserves. Proved gas and oil reserves are the estimated quantities of natural gas, crude oil and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions. Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (a) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

Estimates of proved reserves do not include the following: (a) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves"; (b) crude oil, natural gas and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics or economic factors; (c) crude oil, natural gas liquids that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved developed gas and oil reserves. Proved developed gas and oil reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved undeveloped reserves. Proved undeveloped gas and oil reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation.

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, percentage depletion and other carryforwards. Future cash flows are not reduced by financing costs associated with funding future development costs, as the Company generally attempts to fund such expenditures with cash provided by operations.

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.

The Company estimates future development costs utilizing current costs in the oilfield service sector for the planned operations. The actual costs will vary based upon the service sector costs at the time the work is performed and may be higher than the estimates due to difficulties encountered during the drilling operations.

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, 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
Revisions of previous estimates	4,607	(860)	3,747	178	122	300
Purchases of minerals in place	268,490	1,021	269,511	5,481	6	5,487
Extensions and discoveries	174,334	10,220	184,554	582	120	702
Sales of minerals in place	(7,483)	(1,280)	(8,763)	(1,682)	—	(1,682)
Production	(74,927)	(6,331)	(81,258)	(851)	(207)	(1,058)
Estimated reserves at December 31, 2003	978,517	63,311	1,041,828	8,199	1,575	9,774
Proved developed reserves:						
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
December 31, 2003	656,997	53,819	710,816	6,681	1,387	8,068

	Reserve Quantities		
	Liquids (Mbls)		
	United States	Canada	Total
Proved reserves:			
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
Revisions of previous estimates	687	(185)	502
Purchases of minerals in place	—	32	32
Extensions and discoveries	92	317	409
Sales of minerals in place	—	(19)	(19)
Production	(1,243)	(202)	(1,445)
Estimated reserves at December 31, 2003	4,211	1,923	6,134
Proved developed reserves:			
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
December 31, 2003	3,797	1,626	5,423

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

	December 31, 2003		
	United States	Canada	Total
Future cash flows	$ 5,580,971	$423,803	$ 6,004,774
Future production costs	(1,351,051)	(98,561)	(1,449,612)
Future development costs(1)	(388,159)	(24,635)	(412,794)
Future net cash flows before tax	3,841,761	300,607	4,142,368
Future income taxes	(1,158,249)	(86,871)	(1,245,120)
Future net cash flows after tax	2,683,512	213,736	2,897,248
Annual discount at 10%	(1,184,972)	(79,379)	(1,264,351)
Standardized measure of discounted future net cash flows	$ 1,498,540	$134,357	$ 1,632,897
Discounted future net cash flows before income taxes	$ 2,045,122	$176,008	$ 2,221,130

	December 31, 2002		
	United States	Canada	Total
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
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

(1) The Company estimates that it will incur the following amounts to develop proved undeveloped reserves over the next three years (in thousands):

	United States	Canada	Total
2004	$258,034	$ 10,129	$268,163
2005	84,498	4,949	89,447
2006	11,543	3,240	14,783
	$354,075	$ 18,318	$372,393

The costs estimated to develop proved developed non-producing reserves over the next three years are as follows (in thousands):

	United States	Canada	Total
2004	$14,513	$ 4,903	$19,416
2005	1,536	297	1,833
2006	1,906	386	2,292
	$17,955	$ 5,586	$23,541

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

	Year Ended December 31, 2003		
	United States	Canada	Total
Gas and oil sales, net of production costs(1)	$(277,383)	$(35,255)	$(312,638)
Net changes in anticipated prices and production costs	540,198	28,670	568,868
Extensions and discoveries, less related costs	379,152	21,222	400,374
Changes in estimated future development costs	(12,483)	(3,123)	(15,606)
Previously estimated development costs incurred(2)	35,836	4,461	40,297
Net change in income taxes	(365,143)	(3,745)	(368,888)
Purchase of minerals in place	578,524	2,604	581,128
Sales of minerals in place	(14,991)	(2,310)	(17,301)
Accretion of discount	74,461	13,875	88,336
Revision of quantity estimates	20,924	(2,635)	18,289
Changes in production rates and other	(23,724)	9,754	(13,970)
Change in standardized measure	$ 935,371	$ 33,518	$ 968,889

(1) Net of hedging losses of $23.2 million and $4.5 million on United States and Canadian production, respectively.

(2) The actual costs incurred for development of proved undeveloped properties was $33.6 million, and $4.1 million in the United States and Canada, respectively. Development costs incurred on the proved developed non-producing properties were $2.3 million and $0.3 million in the United States and Canada, respectively.

	Year Ended December 31, 2002		
	United States	Canada	Total
Gas and oil sales, net of production costs(3)	$(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(4)	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

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

(4) The actual costs incurred for development of proved undeveloped properties was $29.2 million and $2.5 million in the United States and Canada, respectively. Development costs incurred on the proved developed non-producing properties were $5.5 million and $0.2 million in the United States and Canada, respectively.

	Year Ended December 31, 2001		
	United States	Canada	Total
Gas and oil sales, net of production costs(5)	$ (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(6)	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)

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

(6) The actual costs incurred for development of proved undeveloped properties was $43.5 million and $7.6 million in the United States and Canada, respectively. Development costs incurred on the proved developed non-producing properties were $7.3 million in the United States.

Results of Operations from Producing Activities

Results of operations from producing activities are presented below (in thousands). Income taxes as calculated are based upon the statutory income tax rates in the United States and Canada adjusted for any permanent tax differences and tax credits relating to producing activities:

	December 31, 2003		
	United States	Canada	Total
Gas, oil and natural gas liquid sales	$346,276	$41,396	$387,672
Gas and oil production expense	35,760	6,142	41,902
Taxes on gas and oil production	33,133	—	33,133
Depreciation and depletion	79,498	13,360	92,858
Exploration costs	26,842	2,617	29,459
Accretion	1,183	237	1,420
Income tax expense	62,848	7,332	70,180
Total expenses	239,264	29,688	268,952
Results of operations from producing activities	$107,012	$11,708	$118,720

	December 31, 2002		
	United States	Canada	Total
Gas, oil and natural gas liquid sales	$166,502	$27,774	$194,276
Gas and oil production expense	27,307	4,844	32,151
Taxes on gas and oil production	16,621	—	16,621
Depreciation and depletion	70,199	12,993	83,192
Exploration costs	21,362	1,462	22,824
Income tax expense	11,475	3,771	15,246
Total expenses	146,964	23,070	170,034
Results of operations from producing activities	$ 19,538	$ 4,704	$ 24,242

	December 31, 2001		
	United States	Canada	Total
Gas, oil and natural gas liquid sales	$243,898	$30,133	$274,031
Gas and oil production expense	26,853	5,207	32,060
Taxes on gas and oil production	21,020	—	21,020
Depreciation and depletion	53,477	11,841	65,318
Exploration costs	32,060	2,135	34,195
Income tax expense	40,881	4,873	45,754
Total expenses	174,291	24,056	198,347
Results of operations from producing activities	$ 69,607	$ 6,077	$ 75,684

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

Not applicable

ITEM 9a. ***Controls and Procedures***

As of the end of the period covered by this report, our management, with the participation of each of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures. These disclosure controls and procedures are designed to provide us with a reasonable assurance that all of the information required to be disclosed by us in our periodic reports filed with the SEC is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed and maintained to ensure that all of the information required to be disclosed by us in our reports is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow those persons to make timely decisions regarding required disclosure.

Based on their evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures are effective to ensure that material information relating to our company is made known to management on a timely basis. Our Chief Executive Officer and Chief Financial Officer noted no significant deficiencies or material weaknesses in the design or operation of our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that are likely to adversely affect our ability to record, process, summarize and report financial information. There have been no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during our last fiscal quarter that has materially affected or is reasonably likely to materially affect our internal control over financial reporting.

PART III

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

The information regarding Directors of the Company required by this item will be included in the Company's definitive proxy statement to be filed with the Securities and Exchange Commission and such information is incorporated by reference to the Company's definitive proxy statement. Information concerning the Executive Officers of the Company appears under Executive Officers of the Registrant in Part I of this Annual Report on Form 10-K.

ITEM 11. ***Executive Compensation***

The information regarding compensation of executive officers of the Company required by this item will be included in the Company's definitive proxy statement to be filed with the Securities and Exchange Commission and such information is incorporated by reference to the Company's definitive proxy statement.

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

The information regarding security ownership of certain beneficial owners and management required by this item will be included in the Company's definitive proxy statement to be filed with the Securities and Exchange Commission in conjunction with the Company's 2004 Annual Meeting 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, 2003 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, 2003	Weighted-average exercise price of outstanding options, warrants and rights as of December 31, 2003	Number of shares remaining available for future issuance under equity compensation plans as of December 31, 2003
Equity compensation plans approved by security holders			
1989 Stock Option Plan(1)	250,516	$15.02	—
1999 Long-Term Incentive Plan	1,176,263	$22.32	668,625
2003 Stock Option Plan	1,117,550	$26.47	682,450
Equity compensation plans not approved by security holders			
1993 Stock Option Plan(2)	2,615,793	$21.40	—
TOTAL	5,160,122	$22.40	1,351,075

(1) The 1989 Stock Option Plan expired on December 12, 1999 so no additional options may be granted.

(2) The 1993 Stock Option Plan expired on February 24, 2003 so no additional options may be granted. This plan is a broad-based plan providing for grants of non-statutory options during its term to directors and officers as well as all other employees. The plan is administered by the Compensation Committee in the same manner as the plans approved by our stockholders.

ITEM 13. *Certain Relationships and Related Transactions*

The 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 in conjunction with its 2004 Annual Meeting and such information is incorporated by reference to the Company's definitive proxy statement.

ITEM 14. *Principal Accounting Fees and Services*

The information regarding principal accounting fees and services required by this item will be included in the Company's definitive proxy statement to be filed with the Securities and Exchange Commission in conjunction with its 2004 Annual Meeting and such information is incorporated by reference to the Company's definitive proxy statement.

PART IV

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

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

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

Form 8-K Item 9. Press release dated December 18, 2003, entitled "Tom Brown, Inc. Announces 2004 Guidance" filed on December 18, 2003.

(c) *Exhibits:*

2.1 — 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) (File No. 000-03880)

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) (Registration No. 333-51320)

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) (File No. 000-03880)

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) (File No. 000-03880)

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) (File No. 000-03880)

10.2 — U.S. Revolving Credit Agreement dated June 27, 2003. (Incorporated by reference to Exhibit 10.1 in the Registrant's Form 10-Q Report for the quarterly period ended June 30, 2003 and filed with the Securities and Exchange Commission on August 14, 2003)

10.3 — Canadian Revolving Credit Agreement dated June 27, 2003. (Incorporated by reference to Exhibit 10.2 in Registrant's Form 10-Q Report for the quarterly period ended June 30, 2003 and filed with the Securities and Exchange Commission on August 14, 2003)

10.4 — Canadian Term Credit Agreement dated June 27, 2003. (Incorporated by reference to Exhibit 10.3 in Registrant's Form 10-Q Report for the quarterly period ended June 30, 2003 and filed with the Securities and Exchange Commission on August 14, 2003)

10.5 — Senior Subordinated Credit Agreement dated June 27, 2003. (Incorporated by reference to Exhibit 10.4 in Registrant's Form 10-Q Report for the quarterly period ended June 30, 2003 and filed with the Securities and Exchange Commission on August 14, 2003)

10.6 — Form of Subordinated Indenture of Tom Brown, Inc., dated as of August 5, 2003. (Incorporated by reference to Exhibit 4.3 in the Registrant's Form S-3 and filed with the Securities and Exchange Commission on August 5, 2003)

10.7 — Form of First Supplemental Indenture dated as of September 16, 2003, by and among Tom Brown, Inc., Tom Brown Resources Funding Corp. and U.S. Bank National Association, as Trustee. (Incorporated by reference to Exhibit 4.2 in the Registrant's Form 8-K and filed on September 16, 2003)

Executive Compensation Plans and Arrangements (Exhibits 10.8 through 10.20):

10.8 — Employment Agreement dated January 1, 2003 between the Registrant and James D. Lightner. (Incorporated by reference to Exhibit 10.13 in the Registrant's Form 10-K Report for the fiscal year ended December 31, 2002 and filed with the Securities and Exchange Commission on March 25, 2003)

10.9 — 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) (File No. 000-03880)

10.10* — 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.

10.11 — 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) (File No. 000-03880)

10.12 — 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) (File No. 000-03880)

10.13 — 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) (File No. 000-03880)

10.14 — 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) (File No. 000-03880)

10.15 — 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) (File No. 000-03880)

10.16 — 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) (File No. 000-03880)

10.17	—	2003 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, 2003 and filed with the Securities and Exchange Commission on May 15, 2003)
10.18	—	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) (File No. 000-03880)
10.19	—	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) (File No. 000-03880)
10.20	—	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) (Registration No. 33-32774)
21.1*	—	Subsidiaries of the Registrant
23.1*	—	Consent of KPMG LLP
23.3*	—	Consent of Ryder Scott Company
31.1*	—	CEO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	—	CFO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	—	CEO Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	—	CFO Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

* Filed herewith

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 15, 2004

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 15, 2004
/s/ DANIEL G. BLANCHARD Daniel G. Blanchard	Executive Vice President, Chief Financial Officer and Treasurer	March 15, 2004
/s/ RICHARD L. SATRE Richard L. Satre	Controller	March 15, 2004
/s/ DAVID M. CARMICHAEL David M. Carmichael	Director	March 15, 2004
/s/ HENRY GROPPE Henry Groppe	Director	March 15, 2004
/s/ EDWARD S. LEBARON, JR. Edward S. LeBaron, Jr.	Director	March 15, 2004
/s/ ROBERT H. WHILDEN, JR. Robert H. Whilden, Jr.	Director	March 15, 2004
/s/ WAYNE W. MURDY Wayne W. Murdy	Director	March 15, 2004
/s/ JAMES B. WALLACE James B. Wallace	Director	March 15, 2004
/s/ JOHN C. LINEHAN John C. Linehan	Director	March 15, 2004

Exhibit 10.10

AMENDED SCHEDULE TO SEVERANCE AGREEMENT

SEVERANCE AGREEMENTS

OFFICER OR EXECUTIVE	MULTIPLE
James D. Lightner	2.5
Thomas W. Dyk	2
Peter R. Scherer	2
Bruce R. DeBoer	2
Daniel G. Blanchard	2
Clifford C. Drescher	2
Rodney G. Mellott	2
Douglas R. Harris	2
John T. Sanchez	2

Exhibit 21.1

SUBSIDIARIES OF THE REGISTRANT
TOM BROWN, INC.
Subsidiaries of Registrant
December 31, 2003

Name of Subsidiary	Jurisdiction of Incorporation/Organization	Percent Of Ownership
Retex Inc.	Wyoming	100%
Rocno Corporation	Texas	100%
Sauer Drilling Company	Delaware	100%
TBI West Virginia, Inc.	Delaware	100%
TBI Pipeline Company	Delaware	100%
Tom Brown Resources Ltd.	Alberta	100%
TCP Gathering Co.	Colorado	100%

Exhibit 23.1

Consent of KPMG LLP

Independent Auditors' Consent

The Board of Directors
Tom Brown, Inc.

We consent to the incorporation by reference in the registration statements Nos. 33-42991, 33-60191, 33-60842, 333-13157, 333-30069, 333-42011, 333-56577, 333-69353, 333-89031, 333-89033, 333-31426, 333-57814, 333-74268 and 333-106596 on Form S-8 and 333-104896 on Form S-3 of Tom Brown, Inc. of our report dated February 18, 2004, with respect to the consolidated balance sheets of Tom Brown, Inc. as of December 31, 2002 and 2003 and the related consolidated statements of operations, changes in stockholders' equity and cash flows for the years then ended, which report appears in the December 31, 2003 annual report on Form 10-K of Tom Brown, Inc. Our report refers to (i) a change in the method of accounting for asset retirement obligations, (ii) a change in the method of accounting for the impairment of goodwill and other intangible assets, and (iii) a change in the method of accounting for derivative instruments and hedging activities in 2001.

Our report refers to the revisions to the 2001 consolidated financial statements to include the transitional disclosures required by Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets*, which was effective January 1, 2002 and No. 143, *Accounting for Asset Retirement Obligations*, which was effective January 1, 2003. Our report states that we were not engaged to audit, review, or apply any procedures to the 2001 consolidated financial statements of Tom Brown, Inc. other than with respect to such disclosures.

KPMG LLP

Denver, Colorado
March 11, 2004

Exhibit 23.3

CONSENT OF RYDER SCOTT COMPANY

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

As independent petroleum engineers, we hereby consent to the incorporation by reference of our report included in this Form 10-K, into Tom Brown, Inc.'s previously filed Registration Statements on Form S-8 Nos. 33-42991, 33-60191, 33-60842, 333-13157, 333-30069, 333-42011, 333-56577, 333-69353, 333-89031, 333-89033, 333-31426, 333-57814, 333-74268 and 333-106596, and No. 333-104896 on Form S-3.

/s/ RYDER SCOTT COMPANY, L.P.

March 11, 2004

Exhibit 31.1

**CERTIFICATION PURSUANT TO
SECTION 302 OF
THE SARBANES-OXLEY ACT OF 2002**

I, James D. Lightner, Chief Executive Officer, certify that:

1. I have reviewed this annual report on Form 10-K of Tom Brown, Inc. (the "registrant");
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the 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-15(e) and 15d-15(e)) for the registrant and have:
    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the periods in which this annual report is being prepared;
    b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the periods covered by this annual report based on such evaluation; and
    c) Disclosed in this annual report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ JAMES D. LIGHTNER

James D. Lightner
Chairman, Chief Executive Officer and President
March 15, 2004

**CERTIFICATION PURSUANT TO
SECTION 302 OF
THE SARBANES-OXLEY ACT OF 2002**

I, Daniel G. Blanchard, Chief Financial Officer, certify that:

1. I have reviewed this annual report on Form 10-K of Tom Brown, Inc. (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the 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-15(e) and 15d-15(e)) for the registrant and have:

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

   b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the periods covered by this annual report based on such evaluation; and

   c) Disclosed in this annual report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ DANIEL G. BLANCHARD

Daniel G. Blanchard
Executive Vice President, Chief Financial Officer
and Treasurer
March 15, 2004

Exhibit 32.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Tom Brown, Inc. (the "Company") on Form 10-K for the year ended December 31, 2003 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, James D. Lightner, Chairman, Chief Executive Officer and President of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that to my knowledge based upon a review of the report:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company as of the dates and for the periods presented as required by such report.

/s/ JAMES D. LIGHTNER

James D. Lightner
Chairman, Chief Executive Officer and President
March 15, 2004

This certification is provided pursuant to §§ 906 of the Sarbanes-Oxley Act of 2002 and shall not, except to the extent required by the Sarbanes-Oxley Act of 2002, be deemed filed by Tom Brown, Inc. or the certifying officer for purposes of §§ 18 of the Securities Exchange Act of 1934, as amended.

A signed original of this written statement required by §§ 906 has been provided to Tom Brown, Inc. and will be retained by it and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Tom Brown, Inc. (the "Company") on Form 10-K for the year ended December 31, 2003 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Daniel G. Blanchard, Executive Vice President, Chief Financial Officer and Treasurer of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that to my knowledge based upon a review of the report:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company as of the dates and for the periods presented as required by such report.

/s/ DANIEL G. BLANCHARD

Daniel G. Blanchard
Executive Vice President, Chief Financial Officer and Treasurer
March 15, 2004

This certification is provided pursuant to §§ 906 of the Sarbanes-Oxley Act of 2002 and shall not, except to the extent required by the Sarbanes-Oxley Act of 2002, be deemed filed by Tom Brown, Inc. or the certifying officer for purposes of §§ 18 of the Securities Exchange Act of 1934, as amended.

A signed original of this written statement required by §§ 906 has been provided to Tom Brown, Inc. and will be retained by it and furnished to the Securities and Exchange Commission or its staff upon request.

ANNUAL MEETING

The 2003 annual meeting of Tom Brown, Inc. shareholders will be held May 6, 2004, at 9:00 a.m. Mountain Time, at the Hyatt Regency Hotel, 1750 Welton Street, Denver CO. The usual notice and proxy statements will be mailed to all registered shareholders in advance of the meeting.

EXECUTIVE OFFICES

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Denver, Colorado 80202-3918
(303) 260-5000
(303) 260-5001 Fax
Website: www.tombrown.com

COMMON STOCK

Listed as "TBI" on the New York Stock Exchange

TRANSFER AGENT

EquiServe Trust Company, N.A.
P.O. Box 219045
Kansas City, MO 64121-9045
(800) 426-5523
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 L.L.P.
Denver, Colorado

Proudly focused on natural gas.

Clean domestic energy
for the benefit of all Americans.

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