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

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q/A

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

FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2003

OR

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

COMMISSION FILE NUMBER 001-31308

TOM BROWN, INC.

(EXACT NAME OF REGISTRANT AS SPECIFIED IN ITS CHARTER)

DELAWARE (STATE OR OTHER JURISDICTION OF INCORPORATION OR ORGANIZATION)	**95-1949781** (I.R.S. EMPLOYER IDENTIFICATION NO.)
555 SEVENTEENTH STREET **SUITE 1850** **DENVER, COLORADO** (ADDRESS OF PRINCIPAL EXECUTIVE OFFICES)	**80202** (ZIP CODE)

303-260-5000
(REGISTRANT S TELEPHONE NUMBER, INCLUDING AREA CODE)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES ý NO o

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

APPLICABLE ONLY TO CORPORATE ISSUERS:

Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of May 8, 2003.

CLASS OF COMMON STOCK	OUTSTANDING AT MAY 8, 2003
$.10 PAR VALUE	39,420,303

TOM BROWN, INC. AND SUBSIDIARIES

QUARTERLY REPORT FORM 10-Q

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EXPLANATORY NOTE

Tom Brown, Inc. (the "Company") is filing this amendment in response to comments received from the Securities and Exchange Commission regarding the Company s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2003 that was originally filed on May 15, 2003. This report significantly revises the disclosures pertaining to the Company s Unaudited Financial Statements, particularly, the Notes to the Company's Consolidated Financial Statements, and Management s Discussion and Analysis of Financial Condition and Results of Operations. This report continues to speak as of the date of the original filing, and the Company has not updated the disclosure in this report to speak as of a later date. All information contained in this report and the original filing is subject to updating and supplementing as provided in the Company s periodic reports filed with the Securities and Exchange Commission.

TOM BROWN, INC.

555 Seventeenth Street, Suite 1850

Denver, Colorado 80202

QUARTERLY REPORT

Pursuant to Section 13 or 15(d) of the

Securities Exchange Act of 1934

FORM 10-Q

PART I OF TWO PARTS

FINANCIAL INFORMATION

TOM BROWN INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(In thousands, except per share data)

	March 31, 2003	December 31, 2002
	(Unaudited)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 18,269	$ 13,555
Accounts receivable, net of allowance for doubtful accounts	75,785	47,414
Inventories	1,805	1,808
Other	3,266	3,988
Total current assets	99,125	66,765
PROPERTY AND EQUIPMENT, AT COST:		
Gas and oil properties, successful efforts method of accounting	1,006,355	959,807
Gas gathering, processing and other plant	104,728	101,054
Other	37,001	35,930
Total property and equipment	1,148,084	1,096,791
Less: Accumulated depreciation, depletion and amortization	340,274	320,306
Net property and equipment	807,810	776,485
OTHER ASSETS:		
Other assets	7,290	7,702
	$ 914,225	$ 850,952
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 56,582	$ 42,773
Accrued expenses	18,954	21,993
Current portion of bank debt	34,360	
Fair value of derivative instruments	16,680	10,886
Total current liabilities	126,576	75,652

BANK DEBT		100,881		133,172
DEFERRED INCOME TAXES		85,055		73,967
OTHER NON-CURRENT LIABILITIES		20,635		4,543
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; Outstanding 39,415,553 and 39,261,191 shares, respectively		3,942		3,926
Additional paid-in capital		539,012		537,449
Retained earnings		49,548		29,678
Accumulated other comprehensive loss		(11,424)		(7,435)
Total stockholders equity		581,078		563,618
	$	914,225	$	850,952

See accompanying notes to consolidated financial statements.

TOM BROWN, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share amounts)

	Three Months Ended March 31, 2003	Three Months Ended March 31, 2002
	(Unaudited)	
REVENUES:		
Gas, oil and natural gas liquids sales	$ 80,480	$ 41,518
Gathering and processing	6,076	5,264
Marketing and trading	13,854	19,219
Drilling	3,077	1,831
Interest income and other	551	263
Total revenues	104,038	68,095
COSTS AND EXPENSES:		
Gas and oil production	8,185	8,171
Taxes on gas and oil production	6,538	3,908
Trading	13,141	19,801
Gathering and processing costs	2,034	1,521
Drilling operations	2,934	1,938
Exploration costs	6,874	3,583
Impairments of leasehold costs	1,474	1,388
General and administrative	4,847	4,872
Depreciation, depletion and amortization	21,417	22,527
Accretion of asset retirement obligation	292	
Bad debts	152	108
Interest expense and other	3,556	1,369
Total costs and expenses	71,444	69,186
Income (loss) before income taxes and cumulative effect of change in accounting principles	32,594	(1,091)
Income tax (provision) benefit:		
Current	(222)	124
Deferred	(11,575)	596
Income (loss) before cumulative effect of change in accounting principles	20,797	(371)

Cumulative effect of changes in accounting principles		(929)		(18,103)
Net income (loss) attributable to common stock	$	19,868	$	(18,474)
Weighted average number of common shares outstanding:				
Basic		39,482		39,148
Diluted		40,442		39,148
Earnings (loss) per common share Basic:				
Income (loss) before cumulative effect of change in accounting principles	$	.53	$	(.01)
Cumulative effect of change in accounting principles		(.02)		(.46)
Net income (loss) attributable to common stock	$	.51	$	(.47)
Earnings (loss) per common share Diluted:				
Income (loss) before cumulative effect of change in accounting principles	$	.51	$	(.01)
Cumulative effect of change in accounting principles		(.02)		(.46)
Net income (loss) attributable to common stock	$	.49	$	(.47)

See accompanying notes to consolidated financial statements.

TOM BROWN, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended March 31, 2003	Three Months Ended March 31, 2002
	(In thousands	unaudited)
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ 19,868	$ (18,474)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Dry hole costs	3,037	73
Impairments of leasehold costs	1,474	1,388
Depreciation, depletion and amortization	21,417	22,527
Accretion of asset retirement obligation	292	
Cumulative effect of changes in accounting principles	929	18,103
Deferred tax provision	11,575	(596)
Changes in operating assets and liabilities:		
Increase in accounts receivable	(27,905)	(137)
Decrease in inventories	57	130
Decrease (increase) in other current assets	622	(164)
Increase (decrease) in accounts payable and accrued expenses	4,688	(1,774)
Decrease (increase) in other assets, net	860	(684)
Net cash provided by operating activities	36,914	20,392
CASH FLOWS FROM INVESTING ACTIVITIES:		
Proceeds from sales of assets	54	539
Capital expenditures	(33,745)	(36,223)
Changes in accounts payable and accrued expenses for capital expenditures	5,249	(5,006)
Net cash used in investing activities	(28,442)	(40,690)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings of long-term bank debt		14,247
Repayments of long-term bank debt	(5,299)	
Proceeds from exercise of stock options	1,276	397
Net cash (used in) provided by financing activities	(4,023)	14,644
Effect of exchange rate changes on cash	265	(2)
NET CHANGE IN CASH AND CASH EQUIVALENTS	4,714	(5,656)

CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR		13,555		15,196
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$	18,269	$	9,540
Supplemental disclosures of cash flow information:				
Cash paid during the period for:				
Interest	$	1,392	$	901
Income taxes	$	205	$	601
Refund received of income tax deposit	$		$	(6,000)

See accompanying notes to consolidated financial statements.

TOM BROWN, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

(1) Summary of Significant Accounting Policies

The consolidated financial statements included herein have been prepared by Tom Brown, Inc. (the Company) and are unaudited. The financial statements reflect necessary adjustments, all of which were of a recurring nature, and are, in the opinion of management, necessary for a fair presentation. Certain information and footnote disclosures normally included in financial statements prepared in accordance with generally accepted accounting principles have been omitted pursuant to the rules and regulations of the Securities and Exchange Commission. The Company believes that the disclosures presented are adequate to allow the information presented not to be misleading. Users of financial information produced for interim periods are encouraged to refer to the footnotes contained in the Annual Report to Stockholders when reviewing interim financial results.

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. This eliminates the requirement to amortize acquired goodwill; instead, such goodwill shall be reviewed at least annually for impairment. The Company adopted SFAS No. 142 on January 1, 2002, designating its reporting units as (i) gas and oil exploration and development in the United States, (ii) gas and oil exploration and development in Canada, (iii) marketing, gathering and processing and (iv) drilling. The first two reporting units are included in the gas and oil exploration and development segment. A fair value based test was conducted effective January 1, 2002 to evaluate the goodwill originally recorded in conjunction with the January 2001 Stellarton Energy Corporation acquisition. The fair value of the reporting unit was determined with reference to the estimated discounted future net revenues of the underlying gas and oil reserves as of the date of the test and other financial considerations, including going-concern value. This test resulted in the Company recording a non-cash charge of $18.1 million in the quarter ended March 31, 2002. This expense has been reflected in the consolidated statements of operations as a cumulative effect of a change in accounting principle. After this write down, the Company has no goodwill recorded on its consolidated balance sheet or associated amortization expense recorded on its consolidated statements of operations.

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

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

	March 31, 2003		March 31, 2002	
	(In thousands)			
INTANGIBLE ASSETS:				
Proved leasehold acquisition costs	$	346,793	$	316,803
Unproved leasehold acquisition costs		65,427		76,902
Total leasehold acquisition costs		412,220		393,705
Less: Accumulated depletion		110,810		91,658
Net leasehold acquisition costs	$	301,410	$	302,047

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 to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for the recorded amount or incurs a gain or loss upon settlement to the extent the actual costs differ from the recorded liability. SFAS No. 143 was effective for fiscal years beginning after June 15, 2002. The Company adopted SFAS No. 143 on January 1, 2003, and recorded a discounted liability of $14.5 million for the future retirement obligation, an increase to property and equipment of $13.0 million and a charge of $.9 million (net of a deferred tax benefit of $.6 million) as the cumulative effect of a 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. An asset retirement obligation was also recorded for processing plants, compressors and other field facilities.

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

In June 2002, the FASB issued SFAS No. 146, Accounting for Costs Associated with Exit or Disposal Activities. SFAS 146 nullifies the guidance of the Emerging Issues Task Force (EITF) Issue No. 94-3, Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring). SFAS 146 requires that a liability for a cost that is associated with an exit or disposal activity be recognized when the liability is incurred. SFAS 146 also establishes that fair value is the objective for the initial measurement of the liability. The provisions of SFAS 146 are required for exit

or disposal activities that are initiated after December 31, 2002. The adoption of this statement did not impact the Company s financial position or results of operations.

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

In December 2002, the FASB issued SFAS 148, Accounting for Stock-Based Compensation Transition and Disclosure. SFAS No. 148 amends FASB Statement No. 123, Accounting for Stock-Based Compensation to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, this statement amends the disclosure for stock-based employee compensation and the effect of the method used on the reported results. The provisions of SFAS 148 are effective for financial statements with fiscal years ending after December 15, 2002. 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.

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

In October 2002, Emerging Issues Task Force reached a consensus on EITF 02-03. The consensus rescinded EITF 98-10, and as a consequence the Company no longer reports the revenues from its trading activities on a net basis, unless the contracts entered into are considered derivatives. The prior period s financial statements have been reclassified to report the amount of trading revenues from third parties on a gross basis. The margins earned by the Company s marketing subsidiary on the sale of the Company s production are reported as a component of marketing and trading revenues.

(2) Stock Based Compensation

SFAS 123, Accounting for Stock-Based Compensation, as amended by SFAS 148, Accounting for Stock-Based Compensation Transition and Disclosure, outlines a fair value based method of accounting for stock options or similar equity instruments. The Company has opted to continue using the intrinsic value based method, as recommended by Accounting Principles Board (APB) Opinion 25, to measure compensation cost for its stock option plans.

The following table illustrates the effect on net income (loss) and earnings per share if the Company had applied the fair value recognition provisions of SFAS 123 to stock-based employee compensation.

	Three Months Ended March 31, 2003	Three Months Ended March 31, 2002
	(In thousands, except per share amounts)	
Net income (loss) as reported	$ 19,868	$ (18,474)
Deduct: Stock-based employee compensation expense determined under fair value based method for all awards, (net of tax)	(1,240)	(1,600)
Add: Compensation cost included in reported net income (loss) (net of tax)		
Pro forma	$ 18,628	$ (20,074)
Basic net income (loss) per common share:		
As reported	$ .50	$ (.47)
Pro forma	$ .47	$ (.51)
Diluted net income (loss) per common share:		
As reported	$ .49	$ (.47)
Pro forma	$ .46	$ (.51)

The weighted average fair value of options granted during the three months ended March 31, 2003 and 2002 was $22.37 and $24.96, 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 these 2003 and 2002 periods, respectively: (i) risk-free interest rates of 3.35 and 5.29 percent, (ii) expected lives of 7.0 and 7.0 years, (iii) expected volatility of 125.6 and 129.8 percent, and (iv) no dividend yields.

(3) Debt

On March 20, 2001, the Company entered into a $225 million credit facility (the Global Credit Facility). The Global Credit Facility is comprised of: a $75 million line of credit in the U.S. and a $55 million line of credit in Canada, both of which mature on March 20, 2004, and a $95 million five-year term loan in Canada. 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. The Global Credit Facility allows the lenders one scheduled redetermination of the borrowing base each December. In addition, the lenders may elect to require one unscheduled redetermination in the event the borrowing base utilization exceeds

50% of the borrowing base at any time for a period of 15 consecutive business days. At March 31, 2003, the Company had borrowings outstanding under the Global Credit Facility totaling $135.2 million or 45% of the borrowing base at an average interest rate of 4.2%. Of the $135.2 million outstanding, $34.4 million represented advances on the credit line scheduled to mature on March 20, 2004. The Company classified these credit lines as a current liability at March 31, 2003 pending the anticipated extension of the Global Credit Facility. The amount available for borrowing under the Global Credit Facility at March 31, 2003 was $89.8 million.

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

The Global Credit Facility contains certain financial covenants and other restrictions that require the Company to maintain a minimum consolidated tangible net worth of not less than $350 million (adjusted upward by 50% of quarterly net income subsequent to March 31, 2001 and 50% of the net cash proceeds of any stock offering). The Company must also maintain a ratio of indebtedness to earnings before interest expense, state and federal taxes and depreciation, depletion and amortization expense and exploration expense of not more than 3.0 to 1.0 as calculated at the end of each fiscal quarter. The Company was in compliance with all covenants in the first quarter of 2003 and at March 31, 2003.

(4) Income Taxes

The Company has not paid Federal income taxes due to the availability of net operating loss carryforwards and the deductibility of intangible drilling and development costs. The Company has historically been required to pay Alternative Minimum Tax (AMT) on its U.S. activity, but due to a change in U.S. tax policy (The Job Creation and Worker Assistance Act of 2002), an AMT liability was not created in 2002.

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

	March 31, 2003			December 31, 2002
	United States	Canada	Total	Total
Deferred tax assets:				
Net operating loss carryforward	$ 5,757	$ 2,542	$ 8,299	$ 12,122
Percentage depletion carryforward	2,672		2,672	2,520
Alternative minimum tax credit carryforward	4,831		4,831	4,831
Derivative contracts to be settled in a future period	5,188		5,188	3,975
State income tax credits	718		718	698
Other	915		915	333
Total gross deferred tax assets	20,081	2,542	22,623	24,479
Deferred tax liabilities:				
Property and equipment	(68,297)	(39,381)	(107,678)	(98,243)
Other				(203)
Total gross deferred tax liabilities	(68,297)	(39,381)	(107,678)	(98,446)
Net deferred tax liabilities	$ (48,216)	$ (36,839)	$ (85,055)	$ (73,967)

The Company evaluated all appropriate factors to determine the need for a valuation allowance for the net operating loss and AMT carryforwards, including any limitations concerning their use, the levels of taxable income necessary for utilization and tax planning. In this regard, based on recent operating results and expected levels of future earnings, the Company believes it will, more likely than not, generate sufficient taxable income to realize the benefit attributable to the AMT carryforwards and the other deferred tax assets for which valuation allowances were not provided.

The components of the Company s current and deferred tax benefits (provisions) are as follows (in thousands):

	Three Months Ended March 31,	
	2003	2002
Current income tax:		
Federal AMT benefit	$	$ 350
Canadian provision	(76)	(76)
State income and franchise taxes	(146)	(150)
Total current tax provision	(222)	124

Deferred income tax:				
Federal and State provision		(10,522)		(12)
Canadian (provision) benefit		(1,053)		608
Total deferred tax (provision) benefit		(11,575)		596
Total tax (provision) benefit	$	(11,797)	$	720

(5) Marketing and Trading Activities

The Company engages in natural gas trading activities that 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 revenue presented in the financial statements includes the net marketing margin on the Company s production together with the gross trading activity.

(6) Derivative Instruments and Hedging Activities

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

At March 31, 2003, the Company had a current derivative liability of $16.7 million, a deferred tax asset of $6.2 million and accumulated other comprehensive loss of approximately $10.2 million. As of March 31, 2002, the Company had no open derivative contracts.

In April and May 2002, the Company entered into several natural gas costless collars (put and call options) that were based on separate regional price indexes where the Company physically delivers its natural gas. The collars are designated as hedges of production from May 2002 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 designated as hedges of production from January 2003 through October 2003.

As a result of the above transactions, the Company has natural gas hedges, in the form of costless collars and swaps (including related basis swaps) as follows as of March 31, 2003:

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

(7) Segment Information

The Company operates in three reportable segments: (i) gas and oil exploration and development for 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 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):

	Three Months Ended March 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 from external purchasers	$ 41,809	$ 10,257	$ 52,066	$ 73,575	$ 3,077	$ 128,718
Intersegment revenues	28,414		28,414	2,706	1,244	32,364
Total revenues	70,223	10,257	80,480	76,281	4,321	161,082
Marketing and trading expenses offset against related revenues for net presentation				(25,231)		(25,231)
Intersegment eliminations				(31,120)	(1,244)	(32,364)
Total segment revenue	70,223	10,257	80,480	19,930	3,077	103,487
Interest income and other	46		46	386	119	551
Total consolidated revenues	$ 70,269	$ 10,257	$ 80,526	$ 20,316	$ 3,196	$ 104,038
Profit						
Total reportable segment profit	$ 29,133	$ 3,749	$ 32,882	$ 3,760	$ (247)	$ 36,395
Interest expense and other	(2,372)	(1,187)	(3,559)	3		(3,556)
Eliminations					(245)	(245)
Income before income taxes and cumulative effect of change in	$ 26,761	$ 2,562	$ 29,323	$ 3,763	$ (492)	$ 32,594

accounting principle

	Three Months Ended March 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 from external purchasers	$ 22,265	$ 5,700	$ 27,965	$ 52,274	$ 1,831	$ 82,070
Intersegment revenues	13,553		13,553	1,985	2,392	17,930
Total revenues	35,818	5,700	41,518	54,259	4,223	100,000
Marketing and trading expenses offset against related revenues for net presentation				(14,238)		(14,238)
Intersegment eliminations				(15,538)	(2,392)	(17,930)
Total segment revenue	35,818	5,700	41,518	24,483	1,831	67,832
Interest income and other	250		250	4	9	263
Total consolidated revenues	$ 36,068	$ 5,700	$ 41,768	$ 24,487	$ 1,840	$ 68,095
Profit						
Total reportable segment profit	$ (1,036)	$ (187)	$ (1,223)	$ 2,109	$ 55	$ 941
Interest expense and other	(206)	(934)	(1,140)		(74)	(1,214)
Eliminations					(818)	(818)
Income before income taxes and cumulative effect of change in accounting principle	$ (1,242)	$ (1,121)	$ (2,363)	$ 2,109	$ (837)	$ (1,091)

(8) Comprehensive Loss

Comprehensive loss includes certain items recorded directly to stockholders equity and classified as Accumulated Other Comprehensive loss . The following table illustrates the change in comprehensive loss for the three months ended March 31, 2003 and 2002:

	Three Months Ended March 31,			
	2003		2002	
	(In thousands)			
Accumulated Other Comprehensive Loss December 31, 2002 and 2001	$	(7,435)	$	(1,330)
Translation loss		(278)		(64)
Changes in fair value of outstanding hedging positions		(12,160)		
Reclassification adjustment for settled contracts		8,452		
Unrealized loss on marketable security		(3)		(29)
Accumulated Other Comprehensive Loss March 31, 2003 and 2002	$	(11,424)	$	(1,423)

(9) Adoption of SFAS 143, Accounting for 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. Depletion and depreciation recognized in 2003 and subsequent periods will decrease since the salvage values assigned to these assets (now excluded from depreciation and depletion) exceeded the asset retirement costs recorded. 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 Company adopted SFAS No. 143 on January 1, 2003, and recorded a discounted liability of $14.5 million for the future retirement obligation, an increase to property and equipment of $13.0 million and a charge of $.9 million (net of a deferred tax benefit of $.6 million) as the cumulative effect of change in accounting principle. There was no impact on the Company s cash flows as a result of adopting SFAS 143. Subsequent to the adoption of SFAS 143, there has been no significant current period activity with respect to additional asset retirement liabilities, settled liabilities or revisions of estimated cash flows. Accretion expense of $.3 million was recognized in the three months ended March 31, 2003.

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, 2000.

	Three Months Ended March 31, 2002	Year Ended December 31, 2002	December 31, 2001	December 31, 2000
	(In thousands, except per share amounts)			
Net (loss) income				
As reported	$ (18,474)	$ (8,177)	$ 69,503	$ 65,703
Reduction of Accretion of retirement obligation (net of tax)	(169)	(675)	(615)	(429)
Reduction of Depreciation and depletion (net of tax)	112	447	434	281
Pro forma	$ (18,531)	$ (8,405)	$ 69,322	$ 65,555
Basic net income (loss) per common share:				
As reported	$ (.47)	$ (.21)	$ 1.78	$ 1.79
Pro forma	$ (.47)	$ (.21)	$ 1.78	$ 1.79
Diluted net income (loss) per common share:				
As reported	$ (.47)	$ (.20)	$ 1.73	$ 1.76
Pro forma	$ (.47)	$ (.20)	$ 1.72	$ 1.75

(10) Commitments and Contingencies

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

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

(11) Subsequent Event

On May 13, 2003, the Company announced that it had entered into a definitive merger agreement to acquire Matador Petroleum Corporation. Total consideration for the transaction is estimated to be approximately $373 million in cash and assumed debt. For additional information about the transaction, see "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations Capital Resources and Liquidity Growth and Acquisitions."

ITEM 2. ***Management s Discussion and Analysis of Financial Condition and Results of Operations***

Forward-Looking Statements and Risks

The information in this Form 10-Q 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 the Company s Annual Report to Stockholders.

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 the Company s Annual Report to Stockholders.

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

Overview

The following analysis of operations for the three months ended March 31, 2003 and 2002 should be read in conjunction with the Consolidated Financial Statements and associated footnotes included in this Quarterly Report on Form 10-Q, and the Consolidated Financial Statements and associated footnotes contained in the December 31, 2002 Annual Report to Stockholders.

Excluding the cumulative effect of changes in accounting principles, the Company reported net income for the three months ended March 31, 2003 of $20.8 million or $.51 per share (diluted basis) as compared to a net loss of $.4 million or ($.01) per share (diluted basis) for the same period in 2002.

The Company s natural gas, natural gas liquids and oil production decreased 6% in the three months ended March 31, 2003 as compared to the same period in 2002. However, revenue from gas, oil and natural gas liquids sales increased $39.0 million or 94% compared to the prior year s comparable period, due to the increases experienced in natural gas and oil prices in the current period. This increase in gas, oil and natural gas liquid revenues resulted in corresponding increases in taxes on gas and oil production and deferred income tax expense. After these expenses, the impact of the increased natural gas and oil prices in 2003 directly correlates with the increased earnings reported in this period.

The net income and loss recognized in the three months ended March 31, 2003 and 2002 were both impacted by the adoption of new accounting principles during these periods. On 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 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.

Results of Operations

Revenues

During the three month period ended March 31, 2003, revenues from gas, oil and natural gas liquids production increased 94% to $80.5 million, as compared to $41.5 million in 2002. This increase was primarily the result of (i) an increase in average gas prices received by the Company from $1.89 per Mcf in 2002 to $4.04 per Mcf in 2003, which increased revenues $36.1 million, (ii) a decrease in gas sales volumes of 6% to 16.8, Bcf, which decreased revenues by $2.2 million and (iii) and increase in the average oil and natural gas liquids prices received from $12.92 to $22.64, which increased revenues $5.1 million.

Revenues in 2003 were reduced by cash settlements on hedging activities. The natural gas collar and swap transactions considered effective hedges and settled in the three months ended March 31, 2003 resulted in cash settlements of $11.2 million, which were included in gas and oil sales. For the three month period ended March 31, 2002, the Company did not have any natural gas or oil hedging instruments in place.

The following table reflects the Company s revenues, average prices received for gas, oil and natural gas liquids, and volumes of gas, oil and natural gas liquids sold in each of the periods shown:

	Three Months Ended March 31,			
	2003		2002	
	(In thousands)			
Revenues:				
Natural gas sales(1)	$	67,824	$	33,999
Crude oil sales		5,540		4,542
Natural gas liquids		7,116		2,977
Gathering and processing		6,076		5,264
Marketing and trading		13,854		19,219
Drilling		3,077		1,831
Interest income and other		551		263
Total revenues	$	104,038	$	68,095
Natural gas production sold (Mmcf)		16,794		17,942
Crude oil production (Mbbls)		180		235
Natural gas liquid production (Mbbls)		379		347
Natural Gas (per Mcf):				
Price received	$	4.71	$	1.89
Effect of hedges	$	(0.67)	$	
Net sales price	$	4.04	$	1.89
Average crude oil sales price ($/Bbl)	$	30.72	$	19.33
Average natural gas liquid sales price ($/Bbl)	$	18.79	$	8.58

Gathering and processing revenue for the quarter ended March 31, 2003 was $6.1 million, an increase of $.8 million from the same period in 2002. The Company processed additional third-party liquids and benefited from the increase in the natural gas liquids prices on retained products in 2003. A new processing plant was operational in the Paradox Basin of Colorado in the first quarter 2003.

The Company reduced the natural gas volumes associated with trading contracts in 2003, which resulted in a reduction in trading revenue (and associated trading expenses) in the quarter ended March 31, 2003 as compared to the same period in 2002. Net marketing and trading margins has increased in 2003 due to the Company transporting gas into the Mid Continent region to take advantage of higher gas prices in this market. This opportunity resulted from natural gas price differentials between the Rocky Mountain region and the Mid Continent markets in excess of the Company s cost to transport a portion of the Company s natural gas production into the Mid Continent market. This marketing opportunity was not available in the three months ended March 31, 2002.

Drilling revenue associated with the Company s wholly owned subsidiary, Sauer Drilling Company increased 68% in the first quarter of 2003 or $1.2 million as compared to the same period in 2002. In the period ending March 31, 2003, Sauer generated a higher percentage of its contract drilling revenue from third-party contracts not affiliated with Tom Brown, as compared to the same period in 2002. Contract drilling revenues associated with wells operated by the Company and drilled by Sauer are eliminated in consolidation. This change in mix for the quarter resulted in higher drilling revenues despite a decrease in rig utilization rates from 58% in 2002, to 54% in 2003.

Costs and Expenses

Expenses related to gas and oil production for the three months ended March 31, 2003 remained relatively unchanged from the expenses incurred during the same period in 2002. On an Mcfe basis, gas and oil production costs increased to $.41 in 2003 from $.38 in 2002. A 6% decline in production between these periods resulted in these relatively fixed costs being spread over lower volumes.

Taxes on gas and oil production increased by 67% or $2.6 million for the three months ended March 31, 2003 in comparison to the same period in 2002. This increase was attributable to the increase in gas, oil and natural gas liquids prices for the period ended March 31, 2003, as compared to the same period in 2002.

Depreciation, depletion and amortization decreased $1.1 million for the three months ended March 31, 2003 as compared to the same period in 2002. The production decrease of 6% for the period was the primary reason for the decrease.

Gathering and processing costs principally represent costs associated with operating and maintaining the field systems. This expense increased for the three months ended March 31, 2003, as compared to the same period in 2002, by $.5 million, which was attributable to incremental processing costs associated with marketing third-party liquids through the Lisbon plant in the Paradox Basin.

Expenses associated with the Company s exploration activities were $6.9 million for the three months ended March 31, 2003, as compared to $3.6 million for the same period in 2002. The Company recorded $3.0 million of dry hole expense for the period ended March 31, 2003, as compared to $.1 million in the same period of 2002. Capital expenditures of $37.5 million were incurred in the first three months of 2003. During the first three months of 2002, capital expenditures were $39.7 million. As of March 31, 2003, the Company has $12.1 million of costs on exploratory wells in process pending the evaluation of drilling results.

General and administrative expenses have remained flat in the three months ended March 31, 2003, in comparison to the same period in 2002. On an Mcfe basis, general and administrative expenses were $0.24 and $0.23 for the three months ended March 31, 2003 and 2002, respectively.

The Company recorded an income tax provision of $11.8 million associated with the $32.6 million income before the cumulative effect in change of accounting principle for the three months ended March 31, 2003, which represented an effective tax rate of 36.2 percent. For the three months ended March 31, 2002, an income tax benefit of $.7 million was recorded associated with the $1.1 million loss before cumulative effect in change of accounting principle in this period. This tax benefit included an adjustment of $.4 million associated with an alternative minimum tax provision that was eliminated after a tax law change was enacted during that quarter.

Capital Resources and Liquidity

Growth and Acquisitions

The Company continues to pursue opportunities that will add value by increasing its reserve base and presence in significant oil and natural gas producing areas, and further developing the Company s ability to control and market the production of hydrocarbons. As the Company continues to evaluate potential acquisitions and property development opportunities, it expects to benefit from its financing flexibility and the additional leverage potential given the Company s existing capital structure.

The Company has entered into a purchase and sale agreement with an unrelated third party to acquire additional working interests in the Wind River Basin of Wyoming for $17.4 million subject to normal closing adjustments. Closing is anticipated in the second quarter of 2003.

The Company also entered into a definitive merger agreement on May 13, 2003 to acquire Matador Petroleum Corporation ("Matador"), after arm's-length negotiations. Matador is 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 merger was approved by Matador s shareholders on June 13, 2003, and the transaction closed on June 27, 2003. The Company initially funded the acquisition with borrowings under a new $425.0 million senior unsecured bank credit facility and a $155.0 million bridge loan under a senior subordinated credit facility. The new $425.0 million bank credit facility replaced the existing credit facilities of the Company and Matador.

Capital and Exploration Expenditures

The Company s capital and exploration expenditures and sources of financing for the three months ended March 31, 2003 and 2002 are as follows:

	2003	2002
	(In millions)	
CAPITAL AND EXPLORATION EXPENDITURES:		
Exploration costs	$ 10.1	$ 7.5
Development costs	22.7	25.2
Acreage	2.9	1.8
Gas gathering and processing	1.1	4.4
Other	.7	.8
	$ 37.5	$ 39.7
FINANCING SOURCES:		
Common stock issued	$ 1.3	$ .4
Net long term bank debt	(5.3)	14.2
Proceeds from sale of assets	.1	.5
Cash flow provided by operating activities	36.9	20.4
Other	4.5	4.2
	$ 37.5	$ 39.7

The Company anticipates exploration and development expenditures between $175 to $185 million in 2003, with approximately 70% to 75% allocated to 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.

Drilling Rig Obligation

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

Bank Credit Facility

On March 20, 2001, the Company entered into a $225 million credit facility (the Global Credit Facility). The Global Credit Facility is comprised of: a $75 million line of credit in the U.S. and a $55 million line of credit in Canada, both of which mature on March 20, 2004, and a $95 million five-year term loan in Canada. The borrowing base established to support the $225 million line of credit was initially set at $300 million. The Global Credit Facility allows the lenders one scheduled redetermination of the borrowing base each December and, as of May 1, 2002, the borrowing base was re-approved at $300 million. In addition, the lenders may elect to require one unscheduled redetermination in the event the borrowing base utilization exceeds 50% of the borrowing base at any time for a period of 15 consecutive business days. At March 31, 2003, the Company had borrowings outstanding under the Global Credit Facility totaling $135.2 million or 45% of the borrowing base at an average interest rate of 4.2%. Of the $135.2 million outstanding, $34.4 million represented advances on the credit lines scheduled to mature on March 20, 2004. The Company classified these credit lines as a current liability at March 31, 2003 pending the anticipated extension of the Global Credit Facility. The amount available for borrowing under the Global Credit Facility at March 31, 2003 was $89.8 million.

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

The Global Credit Facility contains certain financial covenants and other restrictions that require the Company to maintain a minimum consolidated tangible net worth of not less than $350 million (adjusted upward by 50% of quarterly net income and 50% of the net cash proceeds of any stock offering) and the Company will not permit its ratio of indebtedness to earnings before interest expense, State and Federal taxes and depreciation, depletion and amortization expense and exploration expense to be more than 3.0 to 1.0 as calculated at the end of each fiscal quarter. The Company was in compliance with all covenants during the first three months of 2003 and at March 31, 2003.

Markets and Prices

The Company s revenues and associated cash flows are significantly impacted by changes in gas, oil and natural gas liquids prices. The Company s gas, oil and natural gas liquids production is generally market sensitive as the majority of the Company s production has not been presold at contractually specified prices. During the three months ended March 31, 2003, the average prices received for gas and oil by the Company were $4.04 per Mcf and $30.72 per barrel, as compared to $1.89 per Mcf and $19.33 per barrel in 2002. For natural gas liquids, the average prices received were $18.79 per barrel in the 2003 quarter as compared to $8.58 per barrel for the same period in 2002.

Application of Recently Issued Accounting Standards on Intangible Assets

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

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

	March 31, 2003	March 31, 2002
	(In thousands)	
INTANGIBLE ASSETS:		
Proved leasehold acquisition costs	$ 346,793	$ 316,803
Unproved leasehold acquisition costs	65,427	76,902
Total leasehold acquisition costs	412,220	393,705
Less: Accumulated depletion	110,810	91,658
Net leasehold acquisition costs	$ 301,410	$ 302,047

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

ITEM 3. ***Quantitative and Qualitative Disclosure About Market Risk***

The Company utilizes various financial instruments that inherently have some degree of market risk. The primary sources of market risk include fluctuations in commodity prices and interest rates. The Company does not conduct its business through any special purpose entities or have any exposure to off-balance sheet financing arrangements.

Commodity Price Fluctuations

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 accrued gains or losses upon maturity or termination of the contract, are deferred and recognized in income when the associated hedged commodities are produced. In order for natural gas and crude oil swaps 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 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 when incurred.

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

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

Interest Rate Risk

At March 31, 2003, the Company had $135.2 million outstanding under the Global Credit Facility at an average interest rate of 4.2%. 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 2003 will fluctuate based on short-term interest rates. Assuming no change in the amount outstanding during 2003, the impact on interest expense of a ten percent change in the average interest rate would be approximately $.5 million. As the interest rate is variable and is reflective of current market conditions, the carrying value of the Global Credit Facility approximates the fair value.

Foreign Currency Exchange Risk

The Company conduct 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 4. ***Controls and Procedures***

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

TOM BROWN, INC.

555 Seventeenth Street, Suite 1850

Denver, Colorado 80202

QUARTERLY REPORT

Pursuant to Section 13 or 15(d) of the

Securities Exchange Act of 1934

FORM 10-Q

PART II OF TWO PARTS

OTHER INFORMATION

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

The Company s annual meeting of stockholders was held on May 8, 2003. At the meeting, the following persons were elected to serve as Directors of the Company until the annual meeting of stockholders and until their respective successors are duly qualified and elected: (1) John C. Linehan, (2) Wayne W. Murdy, (3) Henry Groppe, (4) Edward W. LeBaron, Jr. (5) James B. Wallace, (6) Robert H. Whilden, Jr. (7) David M. Carmichael, (8) James D. Lightner and (9) Kenneth B. Butler.

Set forth below is a tabulation of votes with respect to each nominee for Director:

	Votes Cast for	**Votes Withheld**	**Broker Non-Votes**
Kenneth B. Butler	35,156,519	199,258	-0-
David M. Carmichael	35,137,253	218,524	-0-
Henry Groppe	29,798,645	5,557,132	-0-
Edward W. LeBaron, Jr.	34,918,534	437,243	-0-
James D. Lightner	35,117,294	238,483	-0-
John C. Linehan	34,922,547	433,230	-0-
Wayne W. Murdy	34,923,447	432,330	-0-
Robert H. Whilden, Jr.	35,139,828	215,949	-0-
James B. Wallace	35,012,828	342,949	-0-

At the annual meeting of stockholders held on May 8, 2003, the stockholders also voted upon the adoption of the 2003 Stock Option Plan. A total of 35,355,777 votes were cast by the holders of the Company s Common Stock of which 31,578,482 voted to adopt the plan, 2,255,772 votes were cast against the adoption of the plan and 1,521,523 votes abstained.

ITEM 6. ***Exhibits and Reports on Form 8-K***

(a)

Exhibit No.	**Description**
10.1*	2003 Stock Option Plan.
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.

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* Filed with the initial filing of this Quarterly Report on Form 10-Q on May 15, 2003.

** Filed herewith.

(b) Reports on Form 8-K

Form 8-K Item 12. Press release dated May 8, 2003, entitled Tom Brown, Inc. Reports First Quarter 2003 Financial and Operating Results filed on May 8, 2003.*

Form 8-K Item 5. Press release dated May 7, 2003 entitled Tom Brown, Inc. Confirms Discussions to Acquire Matador Petroleum filed on May 9, 2003.

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* The information in the Form 8-K furnished pursuant to Item 12 is not considered to be filed for the purposes of Section 18 of the Exchange Act or otherwise subject to the liabilities of that section.

SIGNATURES

Pursuant to the requirements 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. (Registrant)	
	By:	/s/ DANIEL G. BLANCHARD Daniel G. Blanchard *Executive Vice President, Chief Financial Officer and Treasurer* *(Principal Financial Officer)*
August 5, 2003	By:	/s/ RICHARD L. SATRE Richard L. Satre *Controller* *(Chief Accounting Officer)*