BROWN TOM INC /DE
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THE INFORMATION IN THIS PRELIMINARY PROSPECTUS SUPPLEMENT IS NOT COMPLETE AND MAY BE CHANGED. THIS PRELIMINARY PROSPECTUS SUPPLEMENT AND THE ACCOMPANYING PROSPECTUSES ARE NOT AN OFFER TO SELL THESE SECURITIES AND ARE NOT SOLICITING AN OFFER TO BUY THESE SECURITIES IN ANY JURISDICTION WHERE THE OFFER OR SALE IS NOT PERMITTED.

SUBJECT TO COMPLETION, DATED SEPTEMBER 4, 2003

PRELIMINARY PROSPECTUS SUPPLEMENT TO PROSPECTUSES DATED AUGUST 20, 2003

7,500,000 SHARES

(TOM BROWN, INC. LOGO)
TOM BROWN, INC.

COMMON STOCK

We are offering 6,000,000 of the shares to be sold in this offering. The selling stockholder identified in this prospectus supplement is offering an additional 1,500,000 shares. We will not receive any proceeds from the sale of the shares being sold by the selling stockholder.

Our common stock is listed on the New York Stock Exchange under the symbol "TBI." On September 3, 2003, the last reported sales price of our common stock on the NYSE was $26.98 per share.

	PER SHARE	TOTAL
Public offering price	$	$
Underwriting discounts and commissions	$	$
Proceeds to Tom Brown, before expenses	$	$
Proceeds to the selling stockholder, before expenses	$	$

The underwriters may also purchase from us and the selling stockholder, in the same proportion as the shares offered hereby, up to an additional 1,125,000 shares at the public offering price, less the underwriting discount, within 30 days from the date of this prospectus supplement to cover over-allotments, if any.

INVESTING IN OUR COMMON STOCK INVOLVES RISKS. SEE "RISK FACTORS" ON PAGE S-13 OF THIS PROSPECTUS SUPPLEMENT.

NEITHER THE SECURITIES AND EXCHANGE COMMISSION NOR ANY STATE SECURITIES COMMISSION HAS APPROVED OR DISAPPROVED OF THESE SECURITIES OR PASSED ON THE ADEQUACY OR ACCURACY OF THIS PROSPECTUS SUPPLEMENT OR EITHER ACCOMPANYING PROSPECTUS. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

The underwriters expect to deliver the shares of common stock on or about , 2003.

JPMORGAN

WACHOVIA SECURITIES MERRILL LYNCH & CO.

A.G. EDWARDS & SONS, INC.
FIRST ALBANY CORPORATION
GOLDMAN, SACHS & CO.
HOWARD WEIL,
A DIVISION OF LEGG MASON WOOD WALKER, INC.
PETRIE PARKMAN & CO.
RAYMOND JAMES
RBC CAPITAL MARKETS

, 2003

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ABOUT THIS PROSPECTUS SUPPLEMENT

The first part of this document is the prospectus supplement, which describes our business and the specific terms of this offering. The remainder of this document consists of two base prospectuses: an issuer base prospectus and a selling stockholder base prospectus. Both base prospectuses give more general information than the prospectus supplement, some of which may not apply to this offering.

If the information in this prospectus supplement is inconsistent with the information in either of the accompanying prospectuses, you should rely on the information in this prospectus supplement.

You should read this prospectus supplement and the accompanying prospectuses carefully before you invest. These documents contain information you should consider when making your investment decision. In addition, we incorporate important business and financial information in this prospectus supplement and the accompanying prospectuses by reference to other documents. You should read and consider the information in the documents to which we have referred you in "Where You Can Find More Information" in the accompanying prospectuses.

CERTAIN DEFINITIONS AND OTHER INFORMATION

Unless the context requires otherwise or unless otherwise noted, all references in this prospectus supplement to "Tom Brown," "we," "us" or "our" are to Tom Brown, Inc. and its subsidiaries, and the term "common stock" refers to Tom Brown's common stock, $0.10 par value per share, and the associated rights to purchase shares of preferred stock that trade with the common stock. Unless otherwise stated, all information contained in this prospectus supplement assumes that the underwriters' over-allotment option has not been exercised.

On June 27, 2003, we acquired Matador Petroleum Corporation. Unless otherwise indicated, the operating results and reserve information presented in this prospectus supplement are those of Tom Brown and have not been adjusted to reflect the pro forma effect of the Matador acquisition. References in this prospectus supplement to pro forma results and pro forma reserve information assume that we had acquired Matador as of the beginning of the period presented.

We have provided definitions for some of the natural gas and oil industry terms used in this prospectus supplement under "Glossary of common natural gas and oil terms" beginning on page S-44.

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PROSPECTUS SUPPLEMENT SUMMARY

The following summary highlights information contained elsewhere in this prospectus supplement. This summary may not contain all of the information that you should consider before investing in our common stock. You should carefully read this entire document, including the information in this prospectus supplement under the headings "Risk factors" and "Special note regarding forward-looking statements," and the other documents to which we refer you before making an investment decision.

TOM BROWN, INC.

We are 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. Our activities are conducted principally in the Rocky Mountain region of the United States and Canada and the East Texas and Permian basins. We also, to a lesser extent, conduct exploration and development activities in other areas of the continental United States and Canada.

At December 31, 2002, our estimated proved reserves totaled 750 Bcfe, of which 76% were proved developed, and were comprised of approximately 674 Bcf of natural gas, 6 Mmbbls of crude oil and 7 Mmbbls of natural gas liquids. Our estimated proved reserves, on an equivalent basis, were 90% natural gas, and 85% of our total estimated proved reserves were located in the Rocky Mountain region of the United States and Canada. In 2002, we achieved average net production of 234 Mmcfe per day, which implies a reserve life of approximately nine years. Our production increased 12% from 2001 to 2002, with 10% lower operating costs on a per unit basis. For the past three years, we achieved compound annual growth in production and estimated proved reserves of 20% and 13%, respectively. Over the same period, we added estimated proved reserves from all sources that were equal to 215% of our production. Our weighted average finding and development costs for the past three years were $1.29 per Mcfe.

We focus our operations in areas where we have developed significant geological and operational expertise and established critical mass through the strategic accumulation of large, contiguous acreage positions. Our 2002 year-end acreage of 2,132,000 net acres, 87% of which were undeveloped, positions us for continued growth through the drillbit and provides us with a portfolio containing high potential exploration prospects complemented by lower risk development opportunities. We seek to operate the majority of our properties in order to control the timing of capital expenditures and production.

As of December 31, 2002, pro forma for our acquisition of Matador Petroleum Corporation described below, our estimated proved reserves totaled 1.02 Tcfe, of which approximately 89% were natural gas and 73% were proved developed. Fifty-five percent of these pro forma reserves were located in the U.S. Rocky Mountain region, 8% in the Canadian Rocky Mountain region, 19% in the East Texas Basin and 18% in the Permian Basin and other areas. Pro forma 2002 net production averaged 286 Mmcfe per day.

MATADOR ACQUISITION

On June 27, 2003, we acquired Matador Petroleum Corporation for $388 million, which included $267 million of cash and $121 million of assumed debt at closing. We funded the

acquisition of Matador with borrowings under our credit facilities. We estimated Matador's proved reserves, as of December 31, 2002, to be 269 Bcfe, of which 85% were natural gas and 64% were proved developed. The acquisition increased our estimated equivalent proved reserves by approximately 36% and added 165,500 net acres to our leasehold position.

For 2002, Matador's net production averaged 52 Mmcfe per day. We hedged the majority of Matador's expected gas production from proved developed producing reserves through 2004 by entering into a series of costless collar contracts. These contracts have a weighted average floor price of $4.53 per Mmbtu and a weighted average ceiling price of $8.63 per Mmbtu.

The average net production for 2002 and the estimated proved reserves and acreage position of Matador are summarized in the table below.

SUMMARY MATADOR INFORMATION

		AS OF DECEMBER 31, 2002			
AREA	AVERAGE 2002 NET DAILY PRODUCTION (MMCFE)	ESTIMATED PROVED RESERVES (BCFE)*	% GAS	NET DEVELOPED ACRES	NET UNDEVELOPED ACRES
East Texas Basin..........	28	162	95	27,800	33,500
Permian Basin.............	21	82	66	25,500	69,700
Gulf Coast/other..........	3	25	89	4,300	4,700
Total...........	52	269	85	57,600	107,900

* The reserve estimates for Matador were prepared by our petroleum engineering staff, which calculated 269 Bcfe of estimated proved reserves; this calculation was slightly lower than the 282 Bcfe of estimated proved reserves calculated by Matador's independent petroleum consultants.

The Matador acquisition is consistent with our strategy to pursue acquisitions that complement our core areas of activity. We expect that our operational and technical expertise, combined with our financial capability, will allow us to fully exploit Matador's significant prospect inventory. The acquisition of Matador provides many strategic benefits to us, including:

- ATTRACTIVE RESERVE CHARACTERISTICS CONSISTENT WITH OUR CURRENT PROFILE.

The acquisition of Matador increased our estimated proved reserves by approximately 36%, to a pro forma total of approximately 1.02 Tcfe at December 31, 2002, while allowing us to maintain a natural gas weighting of approximately 89% of total reserves and increase our reserve life to approximately 10 years.

In addition, Matador's historical operating performance is characterized by low operating costs.

- COMPLEMENTARY GEOGRAPHIC FIT WITH OUR CORE OPERATIONS.

By acquiring Matador, we have increased our concentration of assets within two of our 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 at December 31, 2002.

The acquisition increased our estimated proved reserve base in these areas from 104 Bcfe to 348 Bcfe.

As of December 31, 2002, prior to the acquisition of Matador, of our 750 Bcfe of estimated proved reserves, 74% were located in the U.S. Rockies, 11% were located in the Canadian Rockies and 15% were located principally in Texas. Through the Matador acquisition, we have increased our reserve base in the East Texas Basin to 19% of our total estimated equivalent proved reserves and increased our reserve base in the Permian Basin and other regions to 18%, while maintaining our position in the Rocky Mountain region.

- INCREASED EXPOSURE TO STRONGER NATURAL GAS PRICE REALIZATIONS.

Natural gas produced in Texas generally sells for a higher realized price than gas produced in the Rockies due to relatively higher Rocky Mountain differentials. With an increased concentration of reserves in Texas as a result of the Matador acquisition, we expect to improve our overall natural gas price realization and reduce our price volatility compared to the New York Mercantile Exchange (NYMEX). In 2002, Matador's realized natural gas price was $2.90 per Mcf, as compared to our 2002 realized natural gas price of $2.19 per Mcf.

- SIGNIFICANT UPSIDE OPPORTUNITIES.

We expect to leverage our operational and technical expertise to fully exploit Matador's undeveloped reserve and acreage position. We have identified 200 development and 550 exploratory drilling locations on Matador's 165,500 net acres. Our current 2003 capital budget for exploration and development spending is estimated to be between $245 million and $255 million, of which approximately 25% has been allocated to the Matador properties.

BUSINESS STRATEGY

Our business strategy is to increase stockholder value through the discovery, acquisition and development of long-lived gas and oil reserves in areas where we have industry knowledge and operational expertise. Our principal investments have been in the natural gas prone basins of North America, which we believe will continue to add long-lived gas and oil reserves at attractive prices. The accumulation of a substantial inventory of exploration and development opportunities, enhanced further by the Matador acquisition, positions us to pursue the following strategic objectives:

- FOCUS ON NORTH AMERICAN BASINS WITH CONCENTRATIONS IN THE ROCKY MOUNTAINS AND TEXAS.

With approximately 55% of pro forma estimated equivalent proved reserves in the U.S. Rockies, 8% in the Canadian Rockies, 19% in the East Texas Basin and 18% in the Permian Basin and other regions, we are focusing our operations in select gas basins characterized by multiple pay sands and significant reserve potential in place. This strategy has enabled us to develop specialized geologic expertise and achieve economies of scale, resulting in competitive finding, development and production costs.

- CAPITALIZE ON EXTENSIVE LAND POSITION.

Our pro forma lease acreage position, of which 85% is undeveloped, provides us with substantial opportunities for future exploration and development activities. Approximately 77% of our pro forma net acreage position is located in the Rocky Mountain region of the United States and Canada, making us one of the largest holders of lease acreage in this region. In the Rockies, we hold, or have options on, 1,777,000 net acres 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 Western Canadian Sedimentary Basin. We have 184,500 net acres in the East Texas Basin and 336,000 net acres in the Permian Basin and other regions, both on a pro forma basis.

- GROW THROUGH EXPLORATION AND DEVELOPMENT DRILLING.

Our growth strategy is founded primarily on creating value through exploration and development drilling, while selectively pursuing acquisitions. Before giving effect to the Matador acquisition, approximately 75% of our estimated equivalent proved reserve additions for the last three years have been a result of exploration and development drilling, with approximately 25% from acquisitions. Our operational and technical personnel have extensive experience in their respective regions, which has contributed to efficient and productive drilling activity. Over the past three years, we have added estimated proved reserves from all sources that were equal to 215% of our production, at a weighted average finding and development cost of $1.29 per Mcfe. We maintain a large portfolio containing high potential exploration prospects complemented by lower risk development projects.

- PURSUE OPPORTUNISTIC ACQUISITIONS.

We will continue to selectively pursue acquisitions of gas and oil properties and leasehold acreage that complement operations in our core areas of activity. Past acquisitions have played an important part of our growth in reserves and inventory of drilling opportunities.

THE OFFERING

COMMON STOCK OFFERED BY US..................	6,000,000 shares
COMMON STOCK OFFERED BY THE SELLING STOCKHOLDER..............................	1,500,000 shares
OVER-ALLOTMENT OPTION.......................	Up to 1,125,000 shares, purchased from us and the selling stockholder, in the same proportion as the shares offered hereby.
COMMON STOCK OUTSTANDING AFTER THE OFFERING.................................	45,579,047 shares
USE OF PROCEEDS............................	We estimate that our net proceeds from this offeri will be approximately $155.0 million after deducti underwriting discounts and commissions and estimat offering expenses payable by us. We intend to use of these net proceeds to repay in full the outstanding indebtedness under our senior subordinated credit facility, which indebtedness w incurred in connection with the Matador acquisitio See "Use of proceeds."

PROCEEDS TO SELLING STOCKHOLDER.............	The net proceeds from the sale by the selling stockholder of 1,500,000 shares of common stock in the offering are estimated to be approximately $38 million. We will not receive any of these proceeds
RISK FACTORS................................	Please see the section entitled "Risk factors" on page S-13 of this prospectus supplement for a discussion of some of the factors you should carefully consider before deciding to invest in shares of our common stock.
NYSE SYMBOL.................................	TBI

The number of shares outstanding after the offering excludes (i) 6,678,785 shares reserved for issuance under our stock option plan, as of September 2, 2003, of which options to purchase 5,018,038 shares at a weighted average option price of $22.13 have been issued, and (ii) 900,000 shares that we may sell to the underwriters upon exercise of their over-allotment option.

SENIOR SUBORDINATED NOTES OFFERING

We and one of our wholly owned subsidiaries, Tom Brown Resources Funding Corp., intend to issue $225 million in aggregate principal amount of senior subordinated notes shortly after this offering of common stock. The sale of the common stock offered hereby is not contingent upon the sale of the senior subordinated notes. We expect to use the net proceeds from the notes offering to repay outstanding indebtedness under our senior global credit facility, including indebtedness incurred in connection with the Matador acquisition. We expect the notes offering to close shortly after the closing of this offering of our common stock, however, there is no guarantee that the notes closing will occur or that $225 million aggregate principal amount of notes will be issued.

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SUMMARY UNAUDITED FINANCIAL AND OPERATING DATA

You should read the following information together with "Selected historical consolidated financial and operating data" and the historical and pro forma financial statements and related notes included or incorporated by reference in this prospectus supplement and the accompanying prospectuses.

The following unaudited summary pro forma statements of operations and operating data shows the pro forma effect of the Matador acquisition. The summary unaudited pro forma statements of operations and operating data for the year ended December 31, 2002 and for the six months ended June 30, 2003 assume the Matador acquisition occurred on January 1, 2002.

The unaudited adjusted balance sheet data at June 30, 2003 reflects the receipt and application of our estimated net proceeds from the sale of common stock in this offering as described under "Use of proceeds."

The unaudited pro forma summary financial data has been prepared to provide an analysis of the financial effects of the Matador acquisition. The pro forma information does not purport to represent what the financial position and results of operations of the combined company would have actually been had the acquisition in fact occurred on the dates indicated, nor is it necessarily indicative of future results of operations.

PRO FORMA INCOME STATEMENT DATA

	YEAR	SIX MONTHS

	ENDED DECEMBER 31, 2002	ENDED JUNE 30, 2003
(in thousands, except per share amounts)		
REVENUES:		
Gas, oil and natural gas liquids sales	$254,212	$217,735
Gathering and processing	20,467	10,868
Marketing and trading, net	5,276	1,058
Drilling	14,347	6,955
Interest income and other	1,547	2,598
Total revenues	295,849	239,214
COSTS AND EXPENSES:		
Gas and oil production	40,737	22,588
Taxes on gas and oil production	21,561	17,675
Gathering and processing costs	6,918	4,071
Drilling operations	13,763	6,031
Exploration costs	26,317	11,523
Impairments of leasehold costs	6,152	3,257
General and administrative	27,338	19,639
Depreciation, depletion and amortization	119,915	59,453
Bad debts	5,222	252
Interest expense and other	29,916	18,544
Total costs and expenses	297,839	163,033
Income (loss) before income taxes and cumulative effect of change in accounting principles	(1,990)	76,181
Income tax (provision) benefit	1,912	(26,240)
Income (loss) before cumulative effect of change in accounting principles	$ (78)	$ 49,941
Weighted average diluted number of common shares outstanding	40,327	40,442
Earnings (loss) per common share--diluted:		
Income (loss) before cumulative effect of change in accounting principles	$ *	$ 1.23

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* Less than $0.01 per share.

	YEAR ENDED DECEMBER 31, 2002	SIX MONTHS ENDED JUNE 30, 2003
PRO FORMA OPERATING DATA:		
Production:		
Natural gas (Mmcf)	87,297	43,180

Crude oil (Mbbls)	1,491	691
Natural gas liquids (Mbbls)	1,382	747
Total production (Mmcfe)	104,535	51,809
Average sales prices:		
Natural gas (per Mcf):		
Price received	$2.31	$4.68
Effect of hedges	--	(0.44)
Net sales price	2.31	4.24
Crude oil (per Bbl)	18.23	30.25
Natural gas liquids (per Bbl)	12.05	18.31
Total (per Mcfe)	2.43	4.20
Expenses per Mcfe:		
Lease operating	0.39	0.44
Taxes on gas and oil production	0.21	0.34
General and administrative	0.26	0.38
Depletion, depreciation and amortization	1.15	1.15

	AT JUNE 30, 2003
(in thousands)	
ADJUSTED BALANCE SHEET DATA:	
Cash and cash equivalents	$ 24,108
Net property and equipment	1,238,152
Total assets	1,475,055
Long-term debt, net of current maturities	388,652
Total stockholders' equity	761,472

SUMMARY RESERVE AND PRODUCTION DATA

The following tables set forth summary data with respect to our estimated proved reserves as of December 31, 2002. Estimates of our gas, oil and natural gas liquids reserves were prepared by our petroleum engineering staff and reviewed by Ryder Scott Company, L.P., independent petroleum consultants. Guidelines established by the Securities and Exchange Commission regarding the present value of future net revenues were utilized to prepare these reserve estimates. 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 require revisions of estimates that were made previously. Accordingly, estimates of reserves and their value are inherently imprecise and are subject to constant revision and change, and they should not be construed as representing the actual quantities of future production or cash flows to be realized from gas and oil properties or the fair market value of such properties.

DECEMBER 31, 2002	
	ESTIMATED PROVED RESERVES BY COMMODITY

	GAS (BCF)	OIL (MMBBLS)	NATURAL GAS LIQUIDS (MMBBLS)	PRO FORMA (BCFE)
Tom Brown................................	674	6	7	750
Matador*.................................	230	7	--	269
Total................................	904	13	7	1,019

REGION	ESTIMATED PROVED RESERVES BY REGION (BCFE) TOM BROWN	MATADOR*	PRO FORMA COMBINED
U.S. ROCKIES:			
Wind River Basin..............................	187	--	187
Green River Basin.............................	112	--	112
Paradox Basin.................................	115	--	115
Piceance Basin................................	141	--	141
Total U.S. Rockies.........................	555	--	555
CANADIAN ROCKIES:			
Western Canadian Sedimentary Basin.............	82	--	82
SOUTHERN REGION:			
East Texas Basin..............................	36	162	198
Permian Basin.................................	68	82	150
Gulf Coast/other..............................	9	25	34
Total Southern Region......................	113	269	382
Total..................................	750	269	1,019

* The reserve estimates for Matador were prepared by our petroleum engineering staff, which calculated 269 Bcfe of estimated proved reserves; this calculation was slightly lower than the 282 Bcfe of estimated proved reserves calculated by Matador's independent petroleum consultants.

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The following table sets forth summary data with respect to our average daily net production of natural gas, oil and natural gas liquids by region for the year ended December 31, 2002 and reserve life at December 31, 2002.

REGION	PRODUCTION BY REGION (MMCFE PER DAY) TOM BROWN	MATADOR	PRO FORMA COMBINED	PRO FOR RESERV LIFE (YEARS

U.S. ROCKIES:			
Wind River Basin	60	--	60
Green River Basin	21	--	21
Paradox Basin	45	--	45
Piceance Basin	33	--	33
Other	2	--	2
Total U.S. Rockies	161	--	161
CANADIAN ROCKIES:			
Western Canadian Sedimentary Basin	24	--	24
SOUTHERN REGION:			
East Texas Basin	20	28	48
Permian Basin	20	21	41
Gulf Coast/other	9	3	12
Total Southern Region	49	52	101
Total	234	52	286

RISK FACTORS

Investing in our common stock will provide you with an equity ownership in Tom Brown. Your shares will be subject to risks inherent in our business. The trading price of your shares will be affected by the performance of our business relative to, among other things, competition, market conditions and general economic and industry conditions. The value of your investment may decrease, resulting in a loss to you. You should consider carefully the information contained in this prospectus supplement, the accompanying prospectuses and the documents we have incorporated by reference. In particular, you should consider carefully the factors discussed under the heading "Business--Risk Factors" set forth in our Annual Report on Form 10-K/A for the year ended December 31, 2002 before deciding to invest in our common stock.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

The information in this prospectus supplement and the accompanying prospectuses includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical or present facts, that address activities, events, outcomes and other matters that we plan, expect, intend, assume, believe, budget, predict, forecast, project, estimate or anticipate (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, using 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 set forth in this prospectus supplement, the accompanying prospectuses and the documents incorporated by reference herein, including those set forth under the caption "Business--Risk Factors" in our Annual Report on Form 10-K/A for the year ended December 31, 2002.

Should one or more of the risks or uncertainties described in this prospectus supplement, the accompanying prospectuses or our Annual Report on Form 10-K/A occur, or should any of the underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety, except as required by law, and therefore disclaim any resulting liability for potentially related damages.

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

SELLING STOCKHOLDER

The following table sets forth certain information, as of September 2, 2003, with respect to the beneficial ownership of our common stock by Chicago Carbon Company, the selling stockholder in this offering and an indirect, wholly owned subsidiary of Union Oil Company of California. Beneficial ownership is calculated based on 39,579,047 shares of our common stock outstanding as of September 2, 2003.

		SHARES OWNED BEFORE OFFERING		SHARES OWNED AFTE OFFERIN	
NAME OF SELLING STOCKHOLDER	SHARES OFFERED HEREBY	NUMBER	PERCENT	NUMBER	PERCEN
Chicago Carbon..................	1,500,000	5,800,000	14.65%	4,300,000	9.43%

This table assumes that the underwriters' over-allotment option has not been exercised. If the underwriters' over-allotment option is exercised in full, the selling stockholder will sell 225,000 shares to the underwriters and will then own 4,075,000 shares, which would be equal to 8.77% of our common stock after giving effect to this offering.

USE OF PROCEEDS

Assuming a public offering price of $26.98 per share, which was the closing price per share of our common stock on September 3, 2003, we expect to receive approximately $155.0 million of net proceeds after deducting underwriting discounts and commissions and estimated offering expenses of $400,000. We will receive no proceeds from the sale of our common stock by the selling stockholder.

We intend to use all of our net proceeds from this offering to repay in full the outstanding indebtedness under our senior subordinated credit facility, which indebtedness was incurred in connection with the Matador acquisition. At September 2, 2003, we had $155 million of borrowings outstanding under our senior subordinated credit facility, bearing interest at 8.5%. The senior subordinated credit facility has a final maturity date of June 27, 2010.

Assuming that we also complete the senior subordinated notes offering, we will apply the estimated net proceeds of $220 million from that offering to our senior global credit facility, in which case total availability under the senior global credit facility will be reduced to $358 million, with $169 million anticipated to be outstanding thereunder after application of the net proceeds of that offering.

CAPITALIZATION

The following table shows:

-- our actual capitalization as of June 30, 2003, which includes the effects of our Matador acquisition; and

-- our capitalization as of June 30, 2003 as adjusted to give effect to the completion of this offering of common stock at the assumed public offering price of $26.98 per share, which was the closing price per share of our common stock on September 3, 2003, and the use of our net proceeds to repay indebtedness under our senior subordinated credit facility as described under "Use of proceeds."

	JUNE 30, 2003	
	ACTUAL	AS ADJUSTED
(in thousands, except share amounts)		
Cash and cash equivalents	$ 24,108	$ 24,108
Long-term debt:		
Senior global credit facility	$ 388,652	$ 388,652
Senior subordinated credit facility	155,000	--
Total debt	543,652	388,652
Stockholders' equity:		
Common stock, $0.10 par value; 55,000,000 shares authorized; 39,537,759 shares issued and outstanding, actual as of June 30, 2003; 45,579,047 shares issued and outstanding, as adjusted	3,954	4,554
Additional paid-in capital	542,944	697,344
Retained earnings	59,574	59,574
Total stockholders' equity	606,472	761,472
Total capitalization	$1,150,124	$1,150,124

This table does not reflect (i) 900,000 shares that we may sell to the underwriters upon exercise of their over-allotment option; or (ii) 6,678,785 shares of common stock reserved for issuance under our stock option plan.

PRICE RANGE OF COMMON STOCK AND DIVIDEND POLICY

Our common stock has been listed on the New York Stock Exchange under the symbol "TBI" since May 16, 2002. Previously, it was included for quotation in the

Nasdaq National Market under the symbol "TMBR." The following table sets forth the high and low sales prices per share of common stock for the periods indicated.

	HIGH	LOW
YEAR ENDED DECEMBER 31, 2001		
First quarter	$35.75	$28.75
Second quarter	33.29	22.38
Third quarter	27.50	19.79
Fourth quarter	27.85	19.65
YEAR ENDED DECEMBER 31, 2002		
First quarter	$27.89	$23.30
Second quarter	29.80	26.00
Third quarter	28.50	20.70
Fourth quarter	26.81	21.80
YEAR ENDED DECEMBER 31, 2003		
First quarter	26.40	22.65
Second quarter	29.28	23.40
Third quarter (through September 3, 2003)	28.20	24.40

On September 3, 2003, the last reported sale price for our common stock, as reported by the NYSE, was $26.98 per share. As of September 2, 2003, there were approximately 1,727 holders of record of our common stock.

We have never declared or paid and do not anticipate declaring or paying any dividends on our common stock in the near future. Rather, we anticipate that we will retain all of our future earnings, if any, for use in the expansion and operation of our business. Any future determination as to the declaration and payment of dividends will be at the discretion of our board of directors and will depend on then existing conditions, including our financial condition, results of operations, contractual restrictions, capital requirements, business prospects and such other factors as our board deems relevant.

UNAUDITED PRO FORMA FINANCIAL DATA

The following unaudited pro forma condensed combined financial information shows the pro forma effect of the Matador acquisition. The unaudited pro forma condensed combined financial information includes pro forma statements of operations for the year ended December 31, 2002 and for the six months ended June 30, 2003, which assume the acquisition occurred on January 1, 2002.

The unaudited pro forma condensed combined financial information has been prepared to provide an analysis of the financial effects of the acquisition. The pro forma information does not purport to represent what the financial position and results of operations of the combined company would have actually been had the acquisition in fact occurred on the dates indicated, nor is it necessarily indicative of the future results of operations.

TOM BROWN, INC.
UNAUDITED PRO FORMA CONDENSED STATEMENT OF OPERATIONS

SIX MONTHS ENDED JUNE 30, 2003

	TOM BROWN HISTORICAL	MATADOR HISTORICAL	PRO FORMA ADJUSTMENTS (NOTE 3)	PRO COMB COM
(in thousands, except per share amounts)				
REVENUES:				
Gas and oil sales	$ 158,960	$58,775	$ --	$217
Gathering and processing	10,868	--	--	10
Marketing and trading, net	1,058	--	--	1
Drilling	6,955			6
Other	2,540	58	--	2
Total revenues	180,381	58,833	--	239
COSTS AND EXPENSES:				
Gas and oil production	16,690	5,898	--	22
Taxes on gas and oil production	13,623	4,052	--	17
Gathering and processing costs	4,071	--	--	4
Cost of drilling operations	6,031	--	--	6
Exploration costs	10,679	--	844(c)	11
Impairments of leasehold costs	2,963	--	294(e)	3
General and administrative	10,650	7,703	1,286(c)	19
Depreciation, depletion, and amortization	44,570	12,444	2,439(d)	59
Accretion	588	196	--	
Bad debt	252	--	--	
Amortization of non-compete agreements	--	--	1,076(f)	1
Interest expense and other	5,818	2,373	8,493(b)	16
Total costs and expenses	115,935	32,666	14,432	163
Income before income taxes and cumulative effect of change in accounting principle	64,446	26,167	(14,432)	76
Income tax provision	(22,293)	(8,998)	5,051(a)	(26
Income (loss) before cumulative effect of change in accounting principle	$42,153	$17,169	$(9,381)	$49
Weighted average number of common shares outstanding	40,487			40
Net income before cumulative effect of change in accounting principle--per common share	$ 1.04			$

See notes to unaudited pro forma condensed combined financial information.

TOM BROWN, INC.
UNAUDITED PRO FORMA CONDENSED STATEMENT OF OPERATIONS
YEAR ENDED DECEMBER 31, 2002

(in thousands, except per share amounts)	TOM BROWN HISTORICAL	MATADOR HISTORICAL	PRO FORMA ADJUSTMENTS (NOTE 3)	PRO F COMBI COMP
REVENUES:				
Gas and oil sales	$194,276	$59,936	$ --	$254,
Gathering and processing	20,467	--	--	20,
Marketing and trading, net	5,276	--	--	5,
Drilling	14,347	--	--	14,
Gain on sale of property	4,114	--	--	4,
Cash paid on derivatives	(2,061)	--	--	(2,
Change in derivative fair value	(345)	--	--	(
Loss on marketable security	(600)	--	--	(
Interest income and other	171	268	--	
Total revenues	235,645	60,204	--	295,
COSTS AND EXPENSES:				
Gas and oil production	32,151	8,586	--	40,
Taxes on gas and oil production	16,621	4,940	--	21,
Gathering and processing costs	6,918	--	--	6,
Cost of drilling operations	13,763	--	--	13,
Exploration costs	22,824	--	3,493(c)	26,
Impairments of leasehold costs	5,564	--	588(e)	6,
General and administrative	18,413	6,550	2,375(c)	27,
Depreciation, depletion, and amortization	91,307	20,766	4,666(d)	116,
Bad debt	5,222	--	--	5,
Amortization of non-compete agreements	--	--	3,176(f)	3,
Interest expense and other	9,726	3,202	16,988(b)	29,
Total costs and expenses	222,509	44,044	31,286	297,
Income (loss) before income taxes and cumulative effect of change in accounting principle	13,136	16,160	(31,286)	(1,
		(5,828)		1,

Income tax (provision) benefit................	(3,210)		10,950(g)	
Income (loss) before cumulative effect of change in accounting principle..............	$ 9,926	$10,332	$ (20,336)	$
Weighted average number of common shares outstanding................................	40,327	--	--	40,
Income (loss) before cumulative effect of change in accounting principle--per common share......................................	$ 0.25			$

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* Less than $0.01 per share.

See notes to unaudited pro forma condensed combined financial information.

TOM BROWN, INC.
NOTES TO UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL INFORMATION

(1) BASIS OF PRESENTATION

The accompanying unaudited pro forma condensed combined statements of operations present the pro forma effects of the Matador acquisition as though the acquisition occurred on January 1, 2002.

(2) METHOD OF ACCOUNTING FOR THE ACQUISITION

We accounted for the acquisition using the purchase method of accounting for business combinations. Under this method of accounting, we were deemed to be the acquirer for accounting purposes. Matador's assets and liabilities were revalued under the purchase method of accounting and recorded at their estimated fair values in conjunction with the merger.

(3) PRO FORMA ADJUSTMENTS RELATED TO THE ACQUISITION

The unaudited pro forma condensed combined statements of operations include the following adjustments:

(a) The income tax provision was adjusted for the tax effect of the pro forma adjustments.

(b) Interest expense increased as a result of our borrowing approximately $280 million in conjunction with the acquisition. Of this amount, $155 million was advanced from a new senior subordinated credit facility and the balance of the funding was provided under a new senior global credit facility. Bank fees of $7.1 million were incurred to obtain these new loan facilities. Pro forma interest expense has been adjusted to include amortization of the loan fees attributable to the amounts borrowed to complete the acquisition.

(c) Adjustments were required to expense certain items under the successful efforts method of accounting we utilize that were previously capitalized by Matador under the full cost method of accounting. These costs were principally associated with exploratory dry holes, delay rentals and seismic costs. Matador also previously capitalized as development cost a portion of its internal costs associated with geological and geophysical staff that are expensed under the successful efforts accounting.

(d) The increase in the cost basis assigned to Matador's gas and oil properties resulted in an increase in depreciation, depletion and amortization expense.

(e) A provision was recognized for leasehold abandonments and expirations based upon the undeveloped leasehold position of Matador. These amounts had previously been capitalized under the full cost method of accounting.

(f) Three officers of Matador entered into non-compete agreements with us in conjunction with the transaction. One agreement covers a 21-month period in exchange for $3.8 million, a portion of which was paid at closing and a portion of which is payable over the term of the agreement. The other two agreements are for terms of three months in exchange for $0.5 million each, the entire amounts of which were paid at closing. A pro forma adjustment has been recorded to reflect the expense associated with these agreements over their terms, assuming the agreements were entered into on January 1, 2002.

(4) APPLICATION OF RECENTLY ISSUED ACCOUNTING STANDARDS ON INTANGIBLE ASSETS

We have been made aware of an issue that has arisen in the industry regarding the application of certain provisions of SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Other Intangible Assets," to companies in the extractive industries, including oil and gas exploration and production companies. The issue is whether the provisions of SFAS No. 141 and SFAS No. 142 require companies to classify costs associated with mineral rights, including both proved and unproved lease acquisition costs, as intangible assets on the balance sheet, apart from other capitalized oil and gas property costs.

Historically, we and Matador have included oil and gas lease acquisition costs as a component of oil and gas properties. Also under consideration is whether SFAS No. 142 requires companies to provide additional disclosures prescribed by SFAS No. 142 for intangible assets for costs associated with mineral rights. In the event it is determined that costs associated with mineral rights are required to be classified as intangible assets, a substantial portion of our capitalized oil and gas property costs and a substantial portion of the acquisition costs attributable to the Matador properties acquired would be separately classified on our balance sheet as intangible assets.

The reclassification of these amounts would not affect the method in which such costs are amortized or the manner in which we assess impairment of capitalized costs. As a result, net income would not be affected by the reclassification if it were to occur.

(5) SUPPLEMENTAL PRO FORMA INFORMATION REGARDING OIL AND GAS OPERATIONS

The following pro forma supplemental information regarding oil and gas operations is presented pursuant to the disclosure requirements of SFAS No. 69, "Disclosures About Oil and Gas Producing Activities."

PRO FORMA COSTS INCURRED

The following tables reflect the costs incurred in oil and gas producing property acquisition, exploration and development activities of us, Matador and the combined company on a pro forma basis for the year ended December 31, 2002 (in thousands).

	TOTAL			UNITED STATES		
	TOM BROWN	MATADOR	COMBINED	TOM BROWN	MATADOR	COMBINED
Costs incurred:						
Proved property acquisition costs......................	$15,878	$ 3,389	$19,267	$15,878	$ 3,389	$19,267
Unproved property acquisition costs......................	9,015	--	9,015	7,601	--	7,601
Exploration costs............	35,035	7,558	42,593	32,482	7,558	40,040
Development costs............	94,567	65,137	159,704	85,319	65,137	150,456
Total.....................	$154,495	$76,084	$230,579	$141,280	$76,084	$217,364

The following tables set forth the changes in the net quantities of natural gas, oil and natural gas liquids reserves of us, Matador and the combined company on a pro forma basis for the year ended December 31, 2002.

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	TOTAL			UNITED STATES		
NATURAL GAS (MMCF)	TOM BROWN	MATADOR	COMBINED	TOM BROWN	MATADOR	COMBINED
Proved reserves:						
Estimated reserves at December 31, 2001........	641,579	168,027	809,606	582,052	168,027	750,079
Revisions of previous estimates.............	10,913	(13,593)	(2,680)	8,304	(13,593)	(5,289)
Purchases of minerals in place.................	15,661	3,414	19,075	15,661	3,414	19,075
Extensions and discoveries...........	84,373	95,444	179,817	79,582	95,444	175,026
Sales of minerals in place.................	(6,332)	--	(6,332)	(6,322)	--	(6,322)
Production..............	(72,167)	(15,130)	(87,297)	(65,781)	(15,130)	(80,911)
Estimated reserves at December 31, 2002........	674,027	238,162	912,189	613,496	238,162	851,658
Proved developed reserves at December 31, 2002........	507,422	133,614	641,036	451,183	133,614	614,797

	TOTAL			UNITED STATES		
OIL (MBBLS)	TOM BROWN	MATADOR	COMBINED	TOM BROWN	MATADOR	COMBINED

Proved reserves:						
Estimated reserves at December 31, 2001........	6,647	5,929	12,576	5,469	5,929	11,398
Revisions of previous estimates............	898	(535)	363	580	(535)	45
Purchases of minerals in place................	34	40	74	34	40	74
Extensions and discoveries..........	451	2,451	2,902	193	2,451	2,644
Sales of minerals in place................	(1,162)	--	(1,162)	(1,162)	--	(1,162)
Production..............	(843)	(648)	(1,491)	(623)	(648)	(1,271)
Estimated reserves at December 31, 2002........	6,025	7,237	13,262	4,491	7,237	11,728
Proved developed reserves at December 31, 2002........	4,551	5,352	9,903	3,299	5,352	8,651

	TOTAL			UNITED STATES		
NATURAL GAS LIQUIDS (MBBLS)	TOM BROWN	MATADOR	COMBINED	TOM BROWN	MATADOR	COMBINED
Proved reserves:						
Estimated reserves at December 31, 2001.......	8,360	--	8,360	6,634	--	6,634
Revisions of previous estimates...........	(628)	--	(628)	(956)	--	(956)
Purchases of minerals in place................	--	--	--	--	--	--
Extensions and discoveries..........	305	--	305	186	--	186
Sales of minerals in place................	--	--	--	--	--	--
Production.............	(1,382)	--	(1,382)	(1,189)	--	(1,189)
Estimated reserves at December 31, 2002.......	6,655	--	6,655	4,675	--	4,675
Proved developed reserves at December 31, 2002....	5,825	--	5,825	4,002	--	4,002

The following table sets forth the standardized measure of discounted future net cash flows relating to proved oil, natural gas and natural gas liquids reserves for us, Matador and the combined company on a pro forma basis as of December 31, 2002 (in thousands).

	TOTAL			UNITED STATES		
	TOM BROWN	MATADOR	COMBINED	TOM BROWN	MATADOR	COMB
Future cash flows......	$2,570,168	$1,279,885	$3,850,053	$2,243,751	$1,279,885	$3,523
Future production costs................	(799,637)	(279,350)	(1,078,987)	(732,739)	(279,350)	(1,012
Future development costs................	(186,363)	(107,251)	(293,614)	(175,085)	(107,251)	(282
Future net cash flows before tax...........	1,584,168	893,284	2,477,452	1,335,927	893,284	2,229
Future income taxes....	(451,706)	(233,146)	(684,852)	(367,271)	(233,146)	(600
Future net cash flows after tax............	1,132,462	660,138	1,792,600	968,656	660,138	1,628
Annual discount at 10%..................	(468,454)	(345,690)	(814,144)	(405,487)	(345,690)	(751
Standardized measure of discounted future net cash flows...........	$664,008	$314,448	$978,456	563,169	314,448	$877
Discounted future net cash flows before income taxes.........	$883,353	$426,114	$1,309,467	$744,608	$426,114	$1,170

The following table includes the components of the changes in the standardized measure of discounted future net cash flows of us, Matador and the combined company on a pro forma basis for the year ended December 31, 2002 (in thousands).

	TOTAL			UNITED STATES			
	TOM BROWN	MATADOR	COMBINED	TOM BROWN	MATADOR	COMBINED	T
Gas and oil sales, net production costs(1)...	$(145,504)	$(46,410)	$(191,914)	$(122,574)	$(46,410)	$(168,984)	$
Net changes in anticipated prices and production costs......	325,690	147,841	473,531	265,587	147,841	413,428	
Extension and discoveries, less related costs.........	112,018	152,612	264,630	95,798	152,612	248,410	
Changes in estimated future development costs.................	(1,813)	--	(1,813)	2,752	--	2,752	
Previously estimated development costs							

incurred.............	39,406	20,853	60,259	37,124	20,853	57,977
Net change in income taxes................	(170,753)	(79,847)	(250,600)	(140,036)	(79,847)	(219,883)
Purchases of minerals in place................	16,970	6,173	23,143	16,970	6,173	23,143
Sales of minerals in place.............	(11,383)	--	(11,383)	(11,383)	--	(11,383)
Accretion of discount...	50,128	15,856	65,984	42,990	15,856	58,846
Revision of quantity estimates............	19,147	(25,474)	(6,327)	7,586	(25,474)	(17,888)
Changes in production rates and other.......	(22,594)	(3,059)	(25,653)	(20,148)	(3,059)	(23,207)
Change in Standardized Measure..............	$211,312	$188,545	$399,857	$174,666	$188,545	$363,211

(1) Net of hedging revenue for Tom Brown of $0.2 million on production in the United States and a $0.2 million hedging loss on Canadian production.

SELECTED HISTORICAL CONSOLIDATED FINANCIAL AND OPERATING DATA

The selected consolidated financial data presented below is derived from our consolidated financial statements. The selected consolidated financial data presented below for the six month periods ended June 30, 2002 and 2003 is derived from our unaudited consolidated financial statements and includes, in the opinion of management, all normal and recurring adjustments necessary to present fairly the data for such periods. The results of operations for the six months ended June 30, 2003 should not be regarded as indicative of results for the full year.

	YEAR ENDED DECEMBER 31,			SIX MONTHS ENDED JUNE 30,	
	2002	2001	2000	2003	2002
(in thousands, except per share amounts)					
STATEMENT OF OPERATIONS DATA					
REVENUES:					
Gas, oil and natural gas liquids sales..........................	$194,276	$274,031	$216,968	$158,960	$94,930
Gathering and processing...........	20,467	23,245	18,283	10,868	9,989
Marketing and trading.............	58,899	124,667	114,211	22,648	36,032
Drilling..........................	14,347	14,828	11,472	6,955	4,581
Interest income and other..........	1,279	12,329	1,346	2,540	2,077
Total revenues.................	289,268	449,100	362,280	201,971	147,609
COSTS AND EXPENSES:					
Gas and oil production............	32,151	32,060	25,488	16,690	16,319
Taxes on gas and oil production....	16,621	21,020	22,105	13,623	8,800

Trading	53,623	122,776	108,370	21,590	35,340
Gathering and processing costs	6,918	10,855	7,212	4,071	3,224
Drilling operations	13,763	11,851	9,715	6,031	4,939
Exploration costs	22,824	34,195	11,001	10,679	11,184
Impairments of leasehold costs	5,564	5,236	3,900	2,963	2,781
General and administrative	18,413	22,742	11,614	10,650	9,365
Depreciation, depletion and amortization	91,307	74,371	50,417	44,570	46,023
Bad debts	5,222	1,043	133	252	216
Interest expense and other	9,726	7,347	5,967	6,406	3,905
Total costs and expenses	276,132	343,496	255,922	137,525	142,096
Income (loss) before income taxes and cumulative effect of change in accounting principles	13,136	105,604	106,358	64,446	5,513
Income tax (provision) benefit	(3,210)	(38,127)	(39,780)	(22,293)	(1,129)
Income (loss) before cumulative effect of change in accounting principles	9,926	67,477	66,578	42,153	4,384
Cumulative effect of change in accounting principles	(18,103)	2,026	--	(929)	(18,103)
Net (loss) income	(8,177)	69,503	66,578	41,224	(13,719)
Preferred stock dividend	--	--	(875)	--	--
Net income (loss) attributable to common stock	$(8,177)	$69,503	$65,703	$41,224	$(13,719)
Weighted average basic number of common shares outstanding	39,217	38,943	36,664	39,478	39,168

	YEAR ENDED DECEMBER 31,			SIX MONTHS ENDED JUNE 30,	
	2002	2001	2000	2003	2002
(in thousands, except per share amounts)					
Weighted average diluted number of common shares outstanding	40,327	40,227	37,897	40,487	40,425
Earnings (loss) per common share -- Basic:					
Income (loss) before cumulative effect of change in accounting principles	$0.25	$1.73	$1.79	$1.07	$0.11
Cumulative effect of change in accounting principles	(0.46)	0.05	--	(0.03)	(0.46)
Net income (loss) attributable to common stock	$(0.21)	$1.78	$1.79	$1.04	$(0.35)

Earnings (loss) per common share --					
Diluted:					
Income (loss) before cumulative effect of change in accounting principles	$0.25	$1.68	$1.76	$1.04	$0.11
Cumulative effect of change in accounting principles	(0.45)	0.05	--	(0.02)	(0.45)
Net income (loss) attributable to common stock	$(0.20)	$1.73	$1.76	$1.02	$(0.34)
BALANCE SHEET DATA (AT END OF PERIOD):					
Cash and cash equivalents	$13,555	$15,196	$17,534	$24,108	$18,911
Working capital (deficit)	(8,887)	11,278	38,139	6,197	19,471
Net property and equipment	776,485	738,526	509,762	1,238,152	772,015
Total assets	850,952	844,975	629,535	1,475,055	863,121
Long-term debt, net of current maturities	133,172	120,570	54,000	543,652	151,815
Total stockholders' equity	563,618	575,228	488,893	606,472	564,535
OPERATING AND OTHER DATA:					
Production:					
Natural gas (Mmcf)	72,167	63,824	51,199	33,764	36,639
Crude oil (Mbbls)	843	881	773	389	455
Natural gas liquids (Mbbls)	1,382	1,217	1,074	747	725
Total production (Mmcfe)	85,517	76,412	62,281	40,580	43,719
Average sales prices:					
Natural gas (per Mcf):					
Price received	$2.19	$3.43	$3.46	$4.53	$2.13
Effect of hedges	--	0.27	--	(0.56)	--
Net sales price	2.19	3.71	3.46	3.97	2.13
Crude oil (per Bbl)	23.41	23.09	28.05	28.80	21.45
Natural gas liquids (per Bbl)	12.05	14.07	16.77	18.31	9.76
Total (per Mcfe)	2.27	3.59	3.48	3.92	2.17
Expenses per Mcfe:					
Lease operating	0.38	0.42	0.41	0.41	0.37
Taxes on gas and oil production	0.19	0.28	0.35	0.34	0.20
General and administrative	0.22	0.30	0.19	0.26	0.21
Depreciation, depletion and amortization	1.07	0.97	0.81	1.10	1.06

BUSINESS

GENERAL

We are 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. Our 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. We also, to a lesser extent, conduct exploration and development activities in other areas of the continental United States and Canada.

At December 31, 2002, our estimated proved reserves totaled 750 Bcfe, of which 76% were proved developed, and were comprised of 674 Bcf of natural gas, 6

Mmbbls of crude oil and 7 Mmbbls of natural gas liquids. Our estimated proved reserves, on an equivalent basis, were 90% natural gas, and 85% of our total estimated proved reserves were located in the Rocky Mountain region of the United States and Canada. In 2002, we achieved average net production of 234 Mmcfe per day, which implies a reserve life of approximately nine years. Our production increased 12% from 2001 to 2002, with 10% lower operating costs on a per unit basis. For the past three years, we achieved compound annual growth in production and estimated proved reserves of 20% and 13%, respectively. Over the same period, we added estimated proved reserves from all sources that were equal to 215% of our production. Our weighted average finding and development costs for the past three years were $1.29 per Mcfe.

We focus our operations in areas where we have developed significant geological and operational expertise and established critical mass through the strategic accumulation of large, contiguous acreage positions. Our 2002 year-end acreage of 2,132,000 net acres, 87% of which were undeveloped, positions us for continued growth through the drillbit and provides us with a portfolio containing high potential exploration prospects complemented by lower risk development opportunities. We seek to operate the majority of our properties in order to control the timing of capital expenditures and production.

As of December 31, 2002, pro forma for our acquisition of Matador Petroleum Corporation described below, our estimated proved reserves totaled 1.02 Tcfe, of which approximately 89% were natural gas and 73% were proved developed. Fifty-five percent of these pro forma reserves were located in the U.S. Rocky Mountain region, 8% in the Canadian Rocky Mountain region, 19% in the East Texas Basin and 18% in the Permian Basin and other areas. Pro forma 2002 net production averaged 286 Mmcfe per day.

On June 27, 2003, we acquired Matador Petroleum Corporation for $388 million, which included $267 million of cash and $121 million of assumed debt at closing. Prior to our acquisition of Matador, Union Oil Company of California, the indirect parent of the selling stockholder, owned approximately 31% of Matador's outstanding common stock. We funded the acquisition of Matador with borrowings under our credit facilities. We estimated Matador's proved reserves, as of December 31, 2002, to be 269 Bcfe, of which 85% were natural gas and 64% were proved developed. The acquisition increased our estimated equivalent proved reserves by approximately 36% (to approximately 1.02 Tcfe) and added 165,500 net acres to our leasehold position. The Matador acquisition is consistent with our strategy to pursue acquisitions that complement our core areas of activity and we expect to combine our

operational and technical expertise, together with our financial capability, to fully exploit Matador's significant prospect inventory.

For 2002, Matador's production averaged 52 Mmcfe per day. Upon signing the acquisition agreement, we hedged the majority of Matador's expected gas production from proved developed producing reserves through 2004 by entering into a series of costless collar contracts. These contracts have a weighted average floor price of $4.53 per Mmbtu and a weighted average ceiling price of $8.63 per Mmbtu.

SUMMARY OF AREAS OF OPERATION

We have long believed in the potential of the Rocky Mountain region. Our operations in the Rockies date back to the 1975 Muddy Ridge discovery in the Wind River Basin of Wyoming. Over time we have diversified within the Rockies, adding positions in the Green River Basin of Wyoming, the Piceance Basin of Colorado, the Paradox Basin of Utah and Colorado and the Western Canadian

Sedimentary Basin of Alberta, Canada. We have also built a substantial position in the East Texas Basin and the Permian and Val Verde basins of West Texas and New Mexico.

	ESTIMATED PROVED RESERVES BY REGION (BCFE) AS OF DECEMBER 31, 2002		
REGION	TOM BROWN	MATADOR*	PRO FORMA COMBINED
U.S. ROCKIES:			
Wind River Basin	187	--	187
Green River Basin	112	--	112
Paradox Basin	115	--	115
Piceance Basin	141	--	141
Total U.S. Rockies	555	--	555
CANADIAN ROCKIES:			
Western Canadian Sedimentary Basin	82	--	82
SOUTHERN REGION:			
East Texas Basin	36	162	198
Permian Basin	68	82	150
Gulf Coast/other	9	25	34
Total Southern Region	113	269	382
Total	750	269	1,019

* The reserve estimates for Matador were prepared by our petroleum engineering staff, which calculated 269 Bcfe of estimated proved reserves; this calculation was slightly lower than the 282 Bcfe of estimated proved reserves calculated by Matador's independent petroleum consultants.

	PRODUCTION BY REGION (MMCFE PER DAY) AS OF DECEMBER 31, 2002			
REGION	TOM BROWN	MATADOR	PRO FORMA COMBINED	PRO FORMA RESERVE LIFE (YEARS)
U.S. ROCKIES:				
Wind River Basin	60	--	60	8.5
Green River Basin	21	--	21	14.6
Paradox Basin	45	--	45	7.0
Piceance Basin	33	--	33	11.7
Other	2	--	2	--
Total U.S. Rockies	161	--	161	9.4

CANADIAN ROCKIES:				
Western Canadian Sedimentary Basin..........................	24	--	24	9.4
SOUTHERN REGION:				
East Texas Basin..................	20	28	48	11.3
Permian Basin.....................	20	21	41	10
Gulf Coast/other..................	9	3	12	7.8
Total Southern Region..........	49	52	101	10.4
Total........................	234	52	286	9.8

The following discussion focuses on areas we consider to be our core areas of operations and those that offer us the greatest opportunities for further exploration and development activities.

WIND RIVER, GREEN RIVER, PARADOX AND PICEANCE BASINS
The Wind River and Green River basins of Wyoming, the Paradox Basin of Utah and Colorado and the Piceance Basin of Colorado account for the major portion of our current and anticipated domestic exploration and development activities, with approximately 54% of our pro forma estimated proved reserves, on an equivalent basis, at December 31, 2002. Prior to the Matador acquisition, at December 31, 2002, we owned interests in 1,278 producing wells in these basins that averaged net daily production of 159 Mmcfe in 2002. We also had approximately 1,565,000 gross (1,224,000 net) developed and undeveloped acres in these basins at December 31, 2002, including option acreage of approximately 281,000 gross undeveloped (253,000 net) acres in the Wind River Basin.

In 2002, we drilled and completed 16 wells in the Wind River Basin, the majority of which were located in the Pavillion Field, where we hold a 92% working interest. In the Piceance Basin, we drilled 26 wells in 2002 (completing 25). The Piceance wells were principally drilled at our 100%-owned White River Dome coal bed methane project in western Colorado.

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

CANADA
The Western Canadian Sedimentary Basin accounted for approximately 8% of our pro forma estimated proved reserves, on an equivalent basis, at December 31, 2002. Our share of production from these basins averaged 24 Mmcfe per day in 2002. Prior to the Matador acquisition, at December 31, 2002, we owned interests in 252 wells and had approximately 540,000 gross (359,000 net) developed and undeveloped acres in this area. In Canada, we drilled 13 wells in 2002 (completing 12). These wells were primarily located in the Carrot Creek and Edson fields, which we operate.

EAST TEXAS BASIN
Our East Texas Basin estimated proved reserves account for approximately 19% of pro forma reserves, on an equivalent basis, as of December 31, 2002. In recent years, we have acquired approximately 80,000 net acres in the James Lime (horizontal) trend of the East Texas Basin. In 2001, we drilled seven wells in the James Lime (horizontal) trend, of which five were initially completed. This large regional play is in its early stages of development and we are working to

determine its potential based upon the initial production rates and variable decline rates of the wells drilled to date.

We continue to participate in a development drilling program in the Mimms Creek Field (Bossier Sands play) in Freestone County, Texas. During 2002, 11 wells were drilled and completed under this program, where our working interests range from 50% to 63%. Since acquiring a majority interest in Mimms Creek in 1996, we have achieved significant exploitation success, increasing the estimated ultimate recovery of reserves in the field by 155% to 120 Bcfe at December 31, 2002. We anticipate applying the technology used on our Mimms Creek Field to Matador's East Texas Basin properties.

The East Texas Basin properties acquired from Matador are located in Freestone County and 10 other counties and generally consist of long-lived, stable reserves with significant development upside. Much success has come from the Freestone-Robertson trend, where we have leasehold positions in over 80,000 gross (40,000 net) acres. Production from these properties averaged 28 Mmcfe per day in 2002.

PERMIAN AND VAL VERDE BASINS

The reserves in the Permian and Val Verde basins and other regions accounted for approximately 18% of our pro forma estimated proved reserves, on an equivalent basis, at December 31, 2002. Our share of production from these basins averaged 28 Mmcfe per day in 2002. We hold between 30% to 50% working interests in approximately 46,800 gross (20,300 net) acres in the Val Verde Basin. The Permian Basin contains significant oil reserves, located primarily in the Sprayberry Field.

In the Deep Valley exploration project area of the Permian Basin, in 2002, we successfully completed a Devonian well with a 50% working interest that commenced production in June 2002 at initial rates approximating 10 Mmcfe per day, declining to 1.6 Mmcfe per day by the end of June 2003. In 2003, we have continued to drill wells and evaluate the Deep Valley project area.

The Permian Basin properties acquired from Matador are focused in the Monument-Skaggs Northwest Area (eastern Lea County), Morrow formation (southeastern New Mexico) and Amacker Tippett area (Upton County, Texas). These properties represent areas where we have

substantial knowledge and operational expertise. Production from these properties averaged 21 Mmcfe per day in 2002.

OTHER BUSINESSES

We market a majority of our operated gas production and some third party gas in the Rocky Mountain region through Retex Inc., our wholly owned marketing subsidiary. Sauer Drilling Company is a wholly owned subsidiary that owns and operates nine drilling rigs in the Rocky Mountain region. Retex and Sauer provide cost savings and operational efficiencies to us by providing services that would otherwise need to be contracted through third parties.

PRODUCTION VOLUMES, UNIT PRICES AND COSTS

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

	VOLUME PRODUCTION AND AVERAGE PRICES		
	2002	2001	2000
PRODUCTION:			
Natural gas (Mmcf)	72,167	63,824	51,199
Crude oil (Mbbls)	843	881	773
Natural gas liquids (Mbbls)	1,382	1,217	1,074
Total production (Mmcfe)	85,517	76,412	62,282
AVERAGE SALES PRICES:			
Natural gas (per Mcf):			
Price received	$ 2.19	$ 3.43	$ 3.46
Effect of hedges	--	0.27	--
Net sales price	2.19	3.71	3.46
Crude oil (per Bbl)	23.41	23.09	28.05
Natural gas liquids (per Bbl)	12.05	14.07	16.77
Total (per Mcfe)	2.27	3.59	3.48

MANAGEMENT

EXECUTIVE OFFICERS AND DIRECTORS

The following persons are our executive officers and directors as of September 3, 2003:

NAME	AGE	POSITION
James D. Lightner	51	Chairman, Chief Executive Officer and President
Daniel G. Blanchard	43	Executive Vice President, Chief Financial Officer and Treasurer
Thomas W. Dyk	50	Executive Vice President and Chief Operating Officer
Peter R. Scherer	46	Executive Vice President
Bruce R. DeBoer	50	Vice President, General Counsel and Secretary
Douglas R. Harris	49	Vice President - Operations
Rodney G. Mellott	46	Vice President - Land and Business Development
Kenneth B. Butler	50	Director
David M. Carmichael	64	Director
Henry Groppe	77	Director
Edward W. LeBaron, Jr.	73	Director
John C. Linehan	64	Director
Wayne W. Murdy	59	Director
James B. Wallace	74	Director
Robert H. Whilden, Jr.	68	Director

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

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

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

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

Bruce R. DeBoer joined Tom Brown 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 Tom Brown in February 2001 as Vice President - Operations. From February 1986 through January 2001, he was employed by Burlington Resources, most recently as Vice President - Production for Burlington Resources Canada in Calgary.

Rodney G. Mellott joined Tom Brown 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.

Kenneth B. Butler has been a director of Tom Brown since 2000. He is Vice President of Unocal Gulf Region USA.

David M. Carmichael has been a director of Tom Brown since 1996. He is also a director of Ensco International Inc. and a director of Natural Resource Partners L.P. Mr. Carmichael is the former Chairman of the Board, Chief Executive Officer and President of American Oil and Gas Corporation.

Henry Groppe has been a director of Tom Brown since 1989. He is a partner in the oil and gas consulting firm of Groppe, Long & Littell.

Edward W. LeBaron, Jr. has been a director of Tom Brown since 1968. He is a partner in LeBaron Ranches L.P., and was formerly a partner in the Pillsbury & Winthrop law firm.

John C. Linehan has been a director of Tom Brown since 2003. He is the retired Executive Vice President and Chief Financial Officer of Kerr-McGee Corporation.

Wayne W. Murdy has been a director of Tom Brown since 2001. He is the Chairman of the Board and Chief Executive Officer of Newmont Mining Corporation.

James B. Wallace has been a director of Tom Brown since 1992. He is a partner in Brownlie, Wallace, Armstrong and Bander Exploration. Mr. Wallace also serves as a director of Delta Petroleum Corporation.

Robert H. Whilden, Jr. has been a director of Tom Brown since 1989. He is Senior Vice President, General Counsel and Secretary of BMC Software, Inc. Mr. Whilden also serves as a director of W-H Energy Services, Inc.

UNITED STATES FEDERAL INCOME TAX CONSIDERATIONS
TO NON-UNITED STATES HOLDERS

The following is a summary of certain United States federal income and estate tax considerations relating to the purchase, ownership and disposition of our common stock by persons that are non-United States holders (as defined below), but does not purport to be a complete analysis of all the potential tax considerations relating thereto. This summary is based upon the Internal Revenue Code of 1986 as amended (the "Code") and regulations, rulings and decisions thereunder now in effect (or, in the case of certain United States Treasury Regulations, now in proposed form), all of which are subject to change, possibly on a retroactive basis. This summary deals only with non-United States holders that will hold our common stock as "capital assets" (generally, property held for investment) and does not address tax considerations applicable to investors that may be subject to special tax rules, including financial institutions, tax-exempt organizations, insurance companies, dealers in securities or currencies, traders in securities that elect to use a mark-to-market method of accounting for their securities holdings, persons that will hold the common stock as a position in a hedging transaction, "straddle" or "conversion transaction" for tax purposes, regulated investment companies, real estate investment trusts, or persons that have a "functional currency" other than the U.S. dollar. If a partnership holds the common stock, the tax treatment of a partner will generally depend upon the status of the partner and the activities of the partnership. If you are a partner of a partnership holding our common stock, you should consult your tax advisor. Moreover, this summary does not discuss alternative minimum tax consequences, if any, or any state, local or foreign tax consequences to holders of the common stock. INVESTORS CONSIDERING THE PURCHASE OF COMMON STOCK SHOULD CONSULT THEIR OWN TAX ADVISORS WITH RESPECT TO THE APPLICATION OF THE UNITED STATES FEDERAL INCOME AND ESTATE TAX LAWS TO THEIR PARTICULAR SITUATIONS, AS WELL AS ANY TAX CONSEQUENCES ARISING UNDER THE LAWS OF ANY STATE, LOCAL OR FOREIGN TAXING JURISDICTION OR UNDER ANY APPLICABLE TAX TREATY.

As used in this discussion, a "non-United States holder" is a beneficial owner of common stock (other than a partnership) that for United States federal income tax purposes is not:

- a citizen or resident of the United States;
- a corporation, or other entity taxable as a corporation for United States federal income tax purposes, that was created or organized in or under the laws of the United States, any state thereof or the District of Columbia;
- an estate whose income is subject to United States federal income taxation regardless of its source; or
- a trust (i) if it is subject to the supervision of a court within the United States and one or more United States persons have the authority to control all substantial decisions of the trust or (ii) that has a valid election in effect under applicable United States Treasury Regulations to be treated as a United States person.

The following discussion addresses certain United States federal income and estate tax consequences of the ownership and disposition of common stock by a non-United States holder.

DIVIDENDS

We have never declared or paid and do not anticipate declaring or paying any dividends on our common stock in the near future. However, if we do pay a dividend, any dividend paid to a non-United States holder of common stock ordinarily will be subject to withholding of United States federal income tax at a rate of 30%, or such lower rate as may be specified under an applicable income tax treaty. In order to receive a reduced treaty rate, a non-United States holder must provide us with an Internal Revenue Service ("IRS") Form W-8BEN or other appropriate version of Form W-8 certifying eligibility for the reduced rate.

Dividends paid to a non-United States holder that are effectively connected with a trade or business conducted by the non-United States holder in the United States (or in the case of an applicable tax treaty, are attributable to a permanent establishment maintained by the non-United States holder in the United States) generally will be exempt from the withholding tax described above and instead will be subject to United States federal income tax on a net income basis. In order to obtain this exemption from withholding tax, a non-United States holder must provide us with an IRS Form W-8ECI properly certifying such exemption. Dividends received by a corporate non-United States holder that are effectively connected with a trade or business conducted by such corporate non-United States holder in the United States (or, in the case of an applicable tax treaty, are attributable to a permanent establishment maintained by such non-United States holder in the United States) may also be subject to an additional branch profits tax at a rate of 30% or such lower rate as may be specified by an applicable tax treaty.

GAIN ON DISPOSITION OF COMMON STOCK

We believe that Tom Brown, Inc. will be treated as a "United States real property holding corporation" for United States federal income tax purposes. Nonetheless, under current law and regulations, a non-United States holder generally will not be subject to United States federal income tax on any gain realized on a disposition of our common stock, provided that (a) the gain is not effectively connected with a trade or business conducted by the non-United States holder in the United States (or, in the case of an applicable tax treaty, is not attributable to a permanent establishment maintained by the non-United States holder in the United States), (b) in the case of a non-United States holder who is an individual and who holds the common stock as a capital asset, such holder is present in the United States for less than 183 days in the taxable year of the sale or other disposition and certain other conditions are met and (c) our common stock continues to be considered regularly traded on an established securities market, and the non-United States holder does not beneficially own, at any time during the five-year period ending on the date of the sale or other disposition, more than 5% of our common stock. Non-United States holders that may be treated as beneficially owning more than 5% of our common stock should consult their own tax advisors with respect to the United States tax consequences of the ownership and disposition of common stock.

FEDERAL ESTATE TAXES

Common stock owned or treated as being owned by a non-United States holder at the time of death will be included in such holder's gross estate for United States federal estate tax purposes, unless an applicable estate tax treaty provides otherwise.

INFORMATION REPORTING AND BACKUP WITHHOLDING

Generally, we must report to the IRS the amount of dividends paid, the name and address of the recipient, and the amount, if any, of tax withheld. A similar report is sent to the non-United States holder. Copies of the information returns reporting those dividends and amounts withheld may also be made available to the tax authorities in the country in which a non-United States holder resides pursuant to the provisions of an applicable tax treaty or exchange of information treaty.

Information reporting and backup withholding generally will not apply to a payment of the proceeds of a sale of common stock effected outside the United States by a foreign office of a foreign broker. However, information reporting requirements (but not backup withholding, unless we have actual knowledge that you are a United States person) will apply to a payment of the proceeds of a sale of common stock effected outside the United States by a foreign office of a broker if the broker (i) is a United States person, (ii) derives 50% or more of its gross income for certain periods from the conduct of a trade or business in the United States, (iii) is a "controlled foreign corporation" as to the United States, or (iv) is a foreign partnership that, at any time during its taxable year, is more than 50% (by income or capital interest) owned by United States persons or is engaged in the conduct of a trade or business in the United States, unless in any such case the broker has documentary evidence in its records that the beneficial owner is a non-United States holder and certain other conditions are met, or the holder otherwise establishes an exemption. Payment of the proceeds of a sale of common stock by a United States office of a broker will be subject to both information reporting and backup withholding unless the holder certifies its non-United States holder status under penalties of perjury and the broker does not have actual knowledge or reason to know that the payee is a United States person, or otherwise establishes an exemption. Backup withholding is not an additional tax. Any amount withheld under the backup withholding rules will be allowed as a credit against the non-United States holder's United States federal income tax liability and any excess may be refundable if the proper information is provided to the IRS.

UNDERWRITING

J.P. Morgan Securities Inc. is the book-running manager of this offering. We, the selling stockholder and the underwriters named below have entered into an underwriting agreement covering the common stock to be offered in this offering. J.P. Morgan Securities Inc. is acting as representative of the underwriters. Subject to the terms and conditions stated in the underwriting agreement, each underwriter named below has severally agreed to purchase, and we and the selling stockholder have severally agreed to sell to that underwriter, the number of shares of our common stock set forth opposite the underwriter's name.

NAME	NUMBER OF SHARES
J.P. Morgan Securities Inc................................	

Wachovia Capital Markets, LLC	
Merrill Lynch, Pierce, Fenner & Smith Incorporated	
A.G. Edwards & Sons, Inc	
First Albany Corporation	
Goldman, Sachs & Co	
Howard Weil, A division of Legg Mason Wood Walker, Inc	
Petrie Parkman & Co., Inc	
Raymond James and Associates, Inc	
RBC Dain Rauscher Inc	
Total	7,500,000

The underwriting agreement provides that if the underwriters purchase any of the shares presented in the table above, then they must purchase all of these shares. No underwriter is obligated to purchase any shares allocated to a defaulting underwriter, except under limited circumstances set forth in the underwriting agreement.

The underwriters are offering the shares of common stock subject to the prior sale of shares, and when, as and if such shares are delivered to and accepted by them, subject to approval of legal matters by their counsel, including the validity of the shares, and other conditions contained in the underwriting agreement. The underwriters reserve the right to withdraw, cancel or modify offers to the public and to reject orders in whole or in part.

The underwriters will initially offer to sell shares to the public at the public offering price shown on the cover page of this prospectus supplement. The underwriters may sell shares to securities dealers at a discount of up to $ per share from the public offering price. Any such securities dealers may resell shares to certain other brokers or dealers at a discount of up to $ per share from the public offering price. After the public offering, the underwriters may vary the public offering price and other selling terms.

If the underwriters sell more shares than the total number shown in the table above, the underwriters have the option to purchase from us and the selling stockholder, in the same proportion as the shares offered hereby, up to an additional 1,125,000 shares of common stock to cover such sales. They may exercise this option during the 30-day period from the date of this prospectus supplement. If any shares are purchased with this option, the underwriters will purchase shares in approximately the same proportions as shown in the table above.

The following table shows the underwriting discounts and commissions that we and the selling stockholder are to pay to the underwriters in connection with this offering. These amounts are shown assuming both no exercise and full exercise of the underwriters' option to purchase 1,125,000 additional shares of our common stock.

UNDERWRITING DISCOUNTS AND COMMISSIONS

	PER SHARE	WITHOUT OVER-ALLOTMENT EXERCISE	WITH OVER-ALLOTME EXERCISE

Public offering price............................	$	$	$
Underwriting discounts and commissions............	$	$	$
Proceeds to Tom Brown, before expenses............	$	$	$
Proceeds to the selling stockholder,			