BROWN TOM INC /DE
Form 8-K/A
August 01, 2003

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SECURITIES AND EXCHANGE

Washington, D.C. 20549

FORM 8-K/A

(Amendment No. 1)

CURRENT REPORT
Pursuant to Section 13 or 15(d) of the
Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) July 30, 2003 (June 27, 2003)

Tom Brown, Inc.

(Exact name of registrant as specified in its charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	**001-31308** (Commission File Number)	**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)

Not Applicable
(Former name, former address and former fiscal year, if changed since last report)

ITEM 2. ACQUISITION OR DISPOSITION OF ASSETS

On June 27, 2003, Tom Brown, Inc. ("Tom Brown") completed its acquisition of Matador Petroleum Corporation, a Texas corporation ("Matador"), for approximately $388 million in cash and assumed debt at closing. A Current Report on Form 8-K was filed on July 11, 2003 to report this transaction.

ITEM 7. FINANCIAL STATEMENTS AND EXHIBITS.

(a)

FINANCIAL STATEMENTS OF BUSINESS ACQUIRED

Audited financial statements for Matador as of December 31, 2002 and 2001 and for the three years ended December 31, 2002, 2001 and 2000 and unaudited financial statements for Matador as of March 31, 2003 and for the three months ended March 31, 2003 and 2002 are included herein.

(b)

PRO FORMA FINANCIAL INFORMATION

Pro forma financial statements as of March 31, 2003 and for the year ended December 31, 2002 and for the three months ended March 31, 2003 are included herein.

(c)

EXHIBITS

23 Consent of KPMG LLP

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Tom Brown, Inc.

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Independent Auditors' Report

The Board of Directors and Stockholders
Matador Petroleum Corporation:

We have audited the accompanying consolidated balance sheets of Matador Petroleum Corporation (a Texas Corporation) and subsidiaries (the Company) as of December 31, 2002 and 2001, and the related consolidated statements of operations, shareholders' equity and cash flows for each of the years in the three-year period ended December 31, 2002. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Matador Petroleum Corporation and subsidiaries as of December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

KPMG LLP
March 6, 2003

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MATADOR PETROLEUM CORPORATION
AND SUBSIDIARIES

Consolidated Balance Sheets

	March 31, 2003	December 31, 2002	December 31, 2001
	(Unaudited)		
Assets			
Current assets:			
Cash and cash equivalents	$ 3,432,500	$ 1,729,921	$ 5,173,635
Accounts receivable:			
Oil and natural gas revenues	14,554,234	7,154,399	5,083,623
Joint interest billings	9,493,532	8,244,069	4,839,630
Other	131,602	962,392	7,000
Prepaid expenses and other	729,074	753,467	603,281
Total current assets	28,340,942	18,844,248	15,707,169
Property and equipment:			
Oil and natural gas properties, at cost, using the full cost method of accounting	328,583,605	298,203,082	217,173,798
Unevaluated property costs	12,382,509	12,173,497	14,673,338
Other property and equipment	3,856,073	3,445,408	3,031,694
Less accumulated depreciation, depletion, and amortization	(89,358,974)	(85,709,644)	(64,955,626)
Total property and equipment, net	255,463,213	228,112,343	169,923,204
Other assets, net	668,780	495,625	418,323
Total assets	$ 284,472,935	$ 247,452,216	$ 186,048,696

		December 31,	
Liabilities and Shareholders' Equity			
Current liabilities:			
Accounts payable	$ 17,853,212	$ 17,706,468	$ 13,690,646
Revenues payable	7,532,860	5,388,333	2,571,724
Drilling advances			687,813
Accrued interest	488,115	336,317	541,980
Dividends payable	219,090	219,090	
Other current liabilities	19,078	9,534	5,582
Total current liabilities	26,112,355	23,659,742	17,497,745
Noncurrent liabilities:			
Notes payable (note 4)	107,480,000	96,280,000	85,680,000
Asset retirement liability	4,522,459		
Deferred income taxes (note 5)	33,277,522	26,741,080	20,241,869
Total noncurrent liabilities	145,279,981	123,021,080	105,921,869
Total liabilities	171,392,336	146,680,822	123,419,614
Commitments and contingencies (note 12)			
Shareholders' equity:			
Common stock, $0.10 par value. Authorized 100,000,000 shares; issued 15,080,791, 15,080,791 and 13,021,989 shares at March 31, 2003, December 31, 2002 and 2001	1,508,079	1,508,079	1,302,199
Additional paid-in capital	73,415,041	73,416,531	45,968,049
Deferred compensation (note 7)	(299,653)	(381,402)	(851,363)
Retained earnings	42,287,402	30,070,595	20,635,866
Treasury stock at cost, 473,308, 474,808 and 553,848 shares at March 31, 2003, December 31, 2002 and 2001	(3,830,270)	(3,842,409)	(4,425,669)
Total shareholders' equity	113,080,599	100,771,394	62,629,082
Total liabilities and shareholders' equity	$ 284,472,935	$ 247,452,216	$ 186,048,696

See accompanying notes to consolidated financial statements.

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MATADOR PETROLEUM CORPORATION
AND SUBSIDIARIES

Consolidated Statements of Operations

	Three Months Ended March 31		Years Ended December 31,		
	2003	**2002**	**2002**	**2001**	**2000**

	Three Months Ended March 31		Years Ended December 31,		
	(Unaudited)	(Unaudited)			
Revenues:					
Natural gas revenues	$ 26,456,368	$ 7,258,264	$ 43,903,215	$ 45,069,044	$ 32,097,165
Oil revenues	5,139,338	3,004,067	16,032,378	18,804,626	16,727,148
Total revenues	31,595,706	10,262,331	59,935,593	63,873,670	48,824,313
Operating costs and expenses:					
Lease operating expense	2,926,478	1,732,488	8,586,441	8,088,269	5,019,205
Production taxes	2,067,682	907,198	4,939,476	5,023,833	3,868,685
Depreciation, depletion, and amortization	5,833,287	4,684,560	20,766,268	16,738,226	10,179,365
General and administrative	1,710,218	1,559,523	6,550,462	7,484,814	3,874,839
Asset retirement expense	96,233				
Total operating costs and expenses	12,633,898	8,883,769	40,842,647	37,335,142	22,942,094
Operating income	18,961,808	1,378,562	19,092,946	26,538,528	25,882,219
Other income (expense):					
Interest expense, net	(914,299)	(897,927)	(3,202,347)	(3,372,922)	(3,675,432)
Interest and other income	44,537	124,991	267,759	128,282	100,952
Total other income (expense)	(869,762)	(772,936)	(2,934,588)	(3,244,640)	(3,574,480)
Income before income taxes	18,092,046	605,626	16,158,358	23,293,888	22,307,739
Income tax benefit (provision):					
Current	340	(322,954)	671,178	(845,062)	(212,715)
Deferred	6,237,027	606,949	(6,499,211)	(7,567,164)	(7,586,436)
Total income tax provision	6,237,367	283,995	(5,828,033)	(8,412,226)	(7,799,151)
Net income	11,854,679	321,631	10,330,325	14,881,662	14,508,588
Cumulative effect of change in accounting principle	581,217				
Accretion of puttable common stock (note 11) and preferred stock dividends (note 10)					773,409
Net income available to common shareholders	$ 12,435,896	$ 321,631	$ 10,330,325	$ 14,881,662	$ 13,735,179
Income per common share basic:					
Income before cumulative effect of change in accounting principle	$ 0.81	$ 0.03	$ 0.74	$ 1.20	$ 1.28

	Three Months Ended March 31		Years Ended December 31,		
Cumulative effect of change in accounting principle	0.04				
Net income attributable to common stock	$ 0.85	$ 0.03	$ 0.74	$ 1.20	$ 1.28
Income per common share diluted:					
Income before cumulative effect of change in accounting principle	$ 0.78	$ 0.03	$ 0.72	$ 1.14	$ 1.10
Cumulative effect of change in accounting principle	0.04				
Net income attributable to common stock	$ 0.82	$ 0.03	$ 0.72	$ 1.14	$ 1.10
Weighted average number of common shares used in computation:					
Basic	14,606,216	12,468,743	13,945,986	12,426,197	10,727,622
Diluted	15,160,650	13,004,810	14,438,814	13,022,252	13,177,917
Cash dividends per share of common stock	$ 0.015	$ 0.012	$ 0.050	$ 0.048	$ 0.040

See accompanying notes to consolidated financial statements.

MATADOR PETROLEUM CORPORATION
AND SUBSIDIARIES

Consolidated Statements of Changes in Shareholders' Equity

Years ended December 31, 2002, 2001, and 2000
Three months ended March 31, 2003 (unaudited)

	Common stock					Treasury stock		
	Shares	Amount	Additional paid-in capital	Deferred compensation	Retained earnings (deficit)	Shares	Amount	Total shareholders' equity
Balance, December 31, 1999	10,684,449	$ 1,068,445	$ 15,597,852	$	$ (6,982,715)		$	$ 9,683,582
Comprehensive income:								
Net income					14,508,588			14,508,588
Total comprehensive income					14,508,588			14,508,588
Expiration of put on common stock (note 11)			22,000,000					22,000,000
Issuance of common stock employee benefit plans	4,200	420	19,273					19,693
Conversion of preferred stock (note 10)	2,333,340	233,334	6,382,993					6,616,327
Purchase of treasury stock (note 11)						(666,669)	(5,333,352)	(5,333,352)
Issuance of treasury stock (note 11)			(88,869)			52,413	419,304	330,435
Common stock dividends					(409,638)			(409,638)
Preferred stock dividends					(792,853)			(792,853)

	Common stock					Treasury stock		
Balance, December 31, 2000	13,021,989	1,302,199	43,911,249		6,323,382	(614,256)	(4,914,048)	46,622,782
Comprehensive income:								
Net income					14,881,662			14,881,662
Total comprehensive income					14,881,662			14,881,662
Paid-in capital stock options (note 7)			2,003,360	(2,003,360)				
Amortization of deferred compensation (note 7)				1,151,997				1,151,997
Issuance of treasury stock (note 11)			53,440			64,786	515,172	568,612
Purchase of treasury stock (note 11)						(4,378)	(26,793)	(26,793)
Common stock dividends					(569,178)			(569,178)
Balance, December 31, 2001	13,021,989	1,302,199	45,968,049	(851,363)	20,635,866	(553,848)	(4,425,669)	62,629,082
Comprehensive income:								
Net income					10,330,325			10,330,325
Total comprehensive income					10,330,325			10,330,325
Issuance of common stock	2,058,802	205,880	27,198,720					27,404,600
Amortization of deferred compensation (note 7)				469,961				469,961
Issuance of treasury stock (note 11)			249,762			87,592	706,553	956,315
Purchase of treasury stock (note 11)						(8,552)	(123,293)	(123,293)
Common stock dividends					(895,596)			(895,596)
Balance, December 31, 2002	15,080,791	$ 1,508,079	$ 73,416,531	$ (381,402)	$ 30,070,595	(474,808)	$ (3,842,409)	$ 100,771,394
Comprehensive income:								
Net income					12,435,896			12,435,896
Total comprehensive income					12,435,896			12,435,896
Amortization of deferred compensation				81,749				81,749
Issuance of treasury stock			(1,490)			1,500	12,139	10,649
Common stock dividends					(219,089)			(219,089)
Balance, March 31, 2003	15,080,791	$ 1,508,079	$ 73,415,041	$ (299,653)	$ 42,287,402	(473,308)	$ (3,830,270)	$ 113,080,599

See accompanying notes to consolidated financial statements.

MATADOR PETROLEUM CORPORATION
AND SUBSIDIARIES

Consolidated Statements of Cash Flows

	Three Months Ended March 31,		Years Ended December 31		
	2003	2002	2002	2001	2000
	(Unaudited)	(Unaudited)			
Cash flows from operating activities:					
Net income	$ 12,435,896	$ 321,631	$ 10,330,325	$ 14,881,662	$ 14,508,588
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation, depletion, and amortization	5,833,287	4,684,560	20,766,268	16,738,226	10,179,365
Asset retirement expense	96,233				
Deferred income tax provision	6,237,027	606,951	6,499,211	7,567,164	7,586,436
Noncash stock-based compensation	81,749	155,678	727,578	1,151,997	
Cumulative effect of change in accounting principle	(581,217)				
Other	6,000	16,500	71,721	65,939	203,377
Change in operating assets and liabilities:					
(Increase) decrease in accounts receivable	(7,818,508)	103,020	(6,286,813)	1,064,821	(5,910,382)
Increase in prepaid expenses and other	(156,112)	(201,428)	(455,253)	(590,407)	(94,110)
Increase (decrease) in accounts and revenues payable	2,291,273	(3,047,428)	6,832,431	7,414,225	3,925,426
Increase (decrease) in other current liabilities	161,342	(635,614)	(889,524)	(37,005)	515,065
Decrease in other long-term liabilities					(509,782)
Net cash provided by operating activities	18,586,970	2,003,870	37,595,944	48,256,622	30,403,983
Cash flows from investing activities:					
Oil and natural gas property capital expenditures	(26,827,063)	(12,574,906)	(75,144,692)	(66,576,590)	(38,549,178)
Oil and natural gas property acquisitions	(638,222)	(97,540)	(3,389,091)	(4,756,245)	(6,375,320)
Other property and equipment capital expenditures	(410,665)	(16,431)	(413,714)	(650,350)	(717,679)
Proceeds from sale of oil and natural gas properties			4,340	301,802	880,559
Net cash used in investing activities	(27,875,950)	(12,688,877)	(78,943,157)	(71,681,383)	(44,761,618)
Cash flows from financing activities:					
Principal payments on notes payable	(800,000)	(8,400,000)	(41,200,000)	(29,850,000)	(19,840,000)
Net proceeds from borrowings	12,000,000	15,300,000	51,800,000	57,150,000	40,450,000
Payments of dividends	(219,090)	(155,852)	(676,506)	(569,178)	(1,202,491)
Issuances of common and treasury stock	10,650	175,327	28,103,298	568,613	350,128
Purchase of treasury stock		(70,800)	(123,293)	(26,793)	(5,333,352)
Net cash provided by financing activities	10,991,560	6,848,675	37,903,499	27,272,642	14,424,285

	Three Months Ended March 31,		Years Ended December 31		
Net increase (decrease) in cash and cash equivalents	1,702,580	(3,836,332)	(3,443,714)	3,847,881	66,650
Cash and cash equivalents, beginning of period	1,729,921	5,173,635	5,173,635	1,325,754	1,259,104
Cash and cash equivalents, end of period	$ 3,432,500	$ 1,337,303	$ 1,729,921	$ 5,173,635	$ 1,325,754
Supplemental disclosures of cash flow information:					
Cash paid (received) during the period for:					
Interest	$ 744,501	$ 921,907	$ 3,411,147	$ 3,373,276	$ 3,675,432
Income taxes			(671,178)	845,062	112,715
Noncash transactions during the period for:					
Stock issued to retirement plan			371,550	289,110	245,702

See accompanying notes to consolidated financial statements.

MATADOR PETROLEUM CORPORATION
AND SUBSIDIARIES

Notes to Consolidated Financial Statements

December 31, 2002 and 2001

(Unaudited with respect to March 31, 2003 and 2002)

(1) Organization

Matador Petroleum Corporation (the Company), a Texas corporation, engages in the exploration, development, and production of oil and natural gas reserves in the United States. The Company's operations are located primarily in the East Texas Basin and the Permian Basin of West Texas and Southeastern New Mexico.

Beginning in 1983, Company Chairman and CEO, Joseph Wm. Foran, founded a series of drilling partnerships and affiliated companies for the purpose of investing in oil and gas properties. Foran Oil Company served as the operating company for purposes of drilling and producing the wells that these partnerships and affiliated companies owned. The partnerships and affiliated companies were rolled up in 1988 to form Matador Petroleum Corporation, with Foran Oil Company changing its name to Matador Operating Company. Matador Petroleum Corporation held the primary assets of the Company while its now wholly owned subsidiary, Matador Operating Company, served as the operating company.

(2) Summary of Significant Accounting Policies

(a) Principles of Consolidation

The consolidated financial statements include the accounts of Matador Petroleum Corporation and its two wholly owned subsidiaries, Matador E&P Company and NZX Corporation. Matador E&P Company includes four wholly owned subsidiaries, Matador Operating Company, Matador Royalty Corporation, Serenity Petroleum, Inc., and Pilot Production Company. All intercompany balances and transactions have been eliminated in consolidation.

(b) Unaudited Interim Information

The unaudited interim financial statements as of March 31, 2003 and for the three months ended March 31, 2003 and 2002, included herein, have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission. Accordingly, they do not include all the information and footnotes required by accounting principles generally accepted in the United States of America for complete financial statements. In the opinion of management, the unaudited interim financial statements contain all adjustments (consisting of normal recurring adjustments) considered necessary for a fair presentation. The interim financial statements are not necessarily indicative of operating results for an entire year.

(c)

Cash and Cash Equivalents

The Company considers all highly liquid investments with original maturities of three months or less to be cash equivalents.

(d)

Property and Equipment

The Company follows the full-cost method of accounting for oil and natural gas properties. Accordingly, all costs associated with the acquisition, exploration, and development of oil and natural gas reserves are capitalized as incurred. Internal costs are capitalized only to the extent they are directly related to acquisition, exploration, or development activities and do not include any costs related to production, selling or general corporate administrative activities. The Company capitalized $2,374,613, $1,789,034, and $1,361,923 of these internal costs in 2002, 2001, and 2000, respectively. If the net capitalized costs of evaluated oil and natural gas properties less related deferred income taxes exceed the estimated present value of after-tax future net cash flows from proved oil and natural gas reserves, discounted at 10%, such excess is charged to operations as an oil and natural gas property impairment. No impairment of net capitalized costs due to the full-cost limitation was necessary in 2002, 2001, or 2000.

The changes in our unevaluated property costs are shown below:

	December 31,		
	2002	**2001**	**2000**
Beginning balance	$ 14,673,338	$ 14,760,462	$ 7,678,881
Exploration	6,951,295	16,925,250	12,069,330
Development	47,896,482	18,839,135	14,520,304
Interest	74,858	353,344	330,776
Total additions to unevaluated properties	54,922,635	36,117,729	26,920,410
Reclasses to full-cost pool	(57,422,476)	(36,204,853)	(19,838,829)
Ending balance	$ 12,173,497	$ 14,673,338	$ 14,760,462

Of the $12,173,497 balance of unevaluated property costs as of December 31, 2002, $4,896,296, $3,086,814, and $2,663,631 were incurred in 2002, 2001, and 2000, respectively. The remaining $1,526,756 was incurred prior to 2000.

Capitalized costs of oil and natural gas properties, including the estimated future costs to develop proved reserves, are amortized on the unit-of-production method based upon production and estimates of proved reserve quantities. Depreciation, depletion, and amortization (DD&A) per Mcfe was $1.09 in 2002, $1.02 in 2001, and $0.87 in 2000. Unevaluated property costs are excluded from the amortization base used to determine DD&A. Unevaluated properties are assessed for impairment on an annual basis or more often if deemed necessary based upon changes in operating or economic conditions. Upon impairment, the costs of the unevaluated properties are immediately included in the amortization base. Exploratory dry hole costs are included in the amortization base immediately upon determination that the well is not productive. Geological and geophysical costs not associated with a specific unevaluated property are included in the amortization base as incurred.

Sales of oil and natural gas properties, except for those held for resale, are accounted for as adjustments to net capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between net capitalized costs and proved reserves of oil and natural gas. All costs relating to production activities and maintenance and repairs are charged to expense when incurred. Significant workovers that increase the properties' reserves are capitalized.

(e)

Capitalized Interest

Pursuant to Statement of Financial Accounting Standards (SFAS) No. 34, *Capitalization of Interest Costs*, interest is capitalized on assets, during work in process, that have been excluded from the amortization base. Capitalized interest costs were $74,858, $353,344, and $330,776 for the years ended December 31, 2002, 2001, and 2000, respectively.

(f)

Revenue Recognition

Revenue is generally recognized from properties as oil and natural gas is produced and sold net of royalties. Revenues from natural gas production are generally recorded using the sales method, net of royalties. Under this method, revenue is recognized based on the cash received rather than the proportionate share of natural gas produced. Natural gas imbalances at December 31, 2002, 2001, and 2000 were insignificant.

The Company has no allowance for doubtful accounts related to its trade accounts receivable for any period.

(g)

Accounting for Stock-Based Employee Compensation Arrangements

The Company has chosen to continue to account for employee stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees*, and the related interpretations in accounting for option plans. Accordingly, compensation cost for stock options is measured as the excess, if any, of the estimated market price of the Company's common stock at the date of the grant over the amount an employee must pay to acquire the stock.

Had compensation cost for the Company's options been determined based on the fair value at the grant dates consistent with SFAS No. 123, the Company's net income would have been decreased to the pro forma amounts indicated below:

	Three months ended March 31,		**Year ended December 31,**		
	2003	**2002**	**2002**	**2001**	**2000**
Net income, available to common shareholders, as reported	$ 12,435,896	$ 321,631	$ 10,330,325	$ 14,881,662	$ 13,735,179
Less total stock-based compensation expense determined under fair value-based method for all awards, net of related tax effects	(75,677)	(88,598)	(404,234)	(476,158)	(264,840)
Pro forma net income	$ 12,360,219	$ 233,033	$ 9,926,091	$ 14,405,504	$ 13,470,339
Earnings per share:					
Basic as reported	$ 0.85	$ 0.03	$ 0.74	$ 1.20	$ 1.28
Basic pro forma	$ 0.84	$ 0.02	$ 0.71	$ 1.16	$ 1.26
Diluted as reported	$ 0.82	$ 0.03	$ 0.72	$ 1.14	$ 1.10
Diluted pro forma	$ 0.82	$ 0.02	$ 0.69	$ 1.11	$ 1.08

The calculated value of stock options granted under these plans, following calculation methods prescribed by SFAS No. 123, uses the Black-Scholes stock option pricing model with the following weighted average assumptions used:

	2002	2001	1999
Expected option life	5 years	7 years	7 years
Risk-free interest rate	4.59%	5.10%	6.16%
Dividend yield	0.25%	0.25%	0.25%

(h)

Earnings Per Share

Pursuant to SFAS No. 128, *Earnings Per Share*, basic earnings per share is computed based upon the weighted average number of common shares outstanding during the periods. Diluted earnings per share is computed based upon the weighted average number of common shares outstanding plus the assumed issuance of common shares for all potentially dilutive securities. See note 6 for a reconciliation of the basic and diluted earnings per share computations.

On October 1, 1999, the Company declared a two-for-one stock split in the form of a 100% stock dividend on the Company's common stock. On July 1, 2001, the Company declared a three-for-one stock split, also in the form of a stock dividend, related to the Company's common stock. All common share and per common share amounts in the accompanying consolidated financial statements and notes have been restated to retroactively effect the 100% stock dividend declared in 1999 and the three-for-one stock split declared on July 1, 2001.

(i)

New Accounting Pronouncements

Effective January 1, 2001, the Company adopted SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. SFAS No. 133, as amended, requires the Company to recognize all derivative instruments (including certain derivative instruments embedded in other contracts) on the balance sheet as either an asset or a liability measured at fair value. At December 31, 2002 and 2001, the Company had not entered into any contracts or utilized any derivative instruments that meet the criteria as defined in this pronouncement.

In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 141, *Business Combinations*. SFAS No. 141 addresses the accounting and reporting for business combinations. SFAS No. 141 requires that all business combinations be accounted for under the purchase method of accounting. SFAS No. 141 also changes the criteria for the separate recognition of intangible assets acquired in a business combination. SFAS No. 141 is effective for all business combinations initiated after June 30, 2001. The adoption of SFAS No. 141 as of July 1, 2001 had no impact on the Company's consolidated financial statements.

Also in June 2001, the FASB issued SFAS No. 142, *Goodwill and Other Intangible Assets*. SFAS No. 142 addresses accounting and reporting for intangible assets acquired, except for those acquired in a business combination. SFAS No. 142 presumes that goodwill and certain intangible assets have indefinite useful lives. Accordingly, goodwill and certain intangibles will not be amortized, but rather will be tested at least annually for impairment. SFAS No. 142 also addresses accounting and reporting for goodwill and other intangible assets subsequent to their acquisition. SFAS No. 142 is effective for fiscal years beginning after December 15, 2001. The adoption of SFAS No. 142 had no impact on the Company's consolidated financial statements.

The Company has 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 companies. The issue is whether the provisions of SFAS No. 141 and SFAS No. 142 require registrants to classify costs associated with mineral rights, including both proved and unproved lease acquisition costs, as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs, and to provide specific footnote disclosures.

Historically, the Company has included oil and gas lease acquisition costs as a component of oil and gas properties. In the event it is determined that costs associated with mineral rights are required to be classified as intangible assets, a substantial portion of the

Company's oil and gas property acquisition costs since the June 30, 2001 effective date of SFAS Nos. 141 and 142 would be separately classified on its balance sheets as intangible assets. However, the Company's results of operations would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with full cost accounting rules. Further, the Company does not believe the classification of oil and gas lease acquisition costs as intangible assets would have any impact on the Company's compliance with covenants under its debt agreements.

In June 2001, the FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations*. SFAS No. 143 addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS No. 143 is effective for financial statements issued for fiscal years beginning after June 15, 2002. The adoption of SFAS No. 143 as of January 1, 2003 resulted in an increase to oil and natural gas properties of approximately $3.0 million and a reduction of accumulated depreciation, depletion, and amortization of approximately $2.2 million. The asset retirement obligation was approximately $4.3 million. The cumulative effect of the change in accounting principle was a gain of approximately $0.6 million, net of taxes of $0.3 million.

In June 2002, the FASB issued SFAS No. 146, *Accounting for Costs Associated With Exit or Disposal Activities*. This statement addresses significant issues relating to the recognition, measurement, and reporting

of costs associated with exit and disposal activities, including restructuring activities. This statement is not expected to have a significant effect on the Company's consolidated financial statements.

In December 2002, the FASB issued SFAS No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure*, which amends SFAS No. 123. This statement provides alternative methods of transition for entities that voluntarily change to the fair value-based method of accounting for stock-based employee compensation, as well as amends certain disclosure requirements of SFAS No. 123. The Company has retained the intrinsic value method of accounting for stock-based employee compensation arrangements, but has adopted the additional disclosure requirements of SFAS No. 148.

(j)

Management's Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities. These estimates and assumptions may also affect disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from these estimates.

The Company's consolidated financial statements are based on a number of significant estimates including oil and natural gas reserve quantities that are the basis for the calculations of depletion and impairment of oil and natural gas properties. The Company's reserve estimates, which are inherently imprecise, are determined by independent outside petroleum engineers.

(k)

Reclassifications

Certain reclassifications have been made to prior year amounts to conform to the current year presentation.

(l)

Risk and Uncertainties

Historically, the market for oil and natural gas has experienced significant price fluctuations. Prices are impacted by supply and demand, seasonal variations, and other factors. Increases or decreases in prices received could have a significant impact on the Company's future results of operations, financial position, and the Company's allowed borrowing base under its credit facility, which was $105.0 million and $95.0 million at December 31, 2002 and 2001, respectively (see note 4).

(m)

Concentrations of Credit Risk

Financial instruments that potentially subject the Company to concentrations of credit risk consist principally of trade accounts receivable. Management believes that the credit risk posed by this concentration is offset by the creditworthiness of the Company's customer base.

(n)

Fair Value of Financial Instruments

The carrying amounts of the Company's cash and cash equivalents, receivables, payables, and accrued expenses approximate fair value due to the short-term maturities of these assets and liabilities. The carrying amount of the Company's notes payable approximates fair value due to the variable, floating interest rate structure of the notes.

(3) Acquisitions

On January 22, 2000, the Company acquired proved oil and natural gas properties valued at approximately $6.1 million for cash equal to the property values. Pro forma results of operations for the Company for the year ended December 31, 2000, assuming the transaction had occurred on January 1, 2000, would not have been materially different and, as such, pro forma results for the year ended December 31, 2000 have not been provided.

(4) Notes Payable

Notes payable of the Company consist of the following:

	December 31,	
	2002	**2001**
Revolving credit note to a syndicate of five banks, collateralized by oil and natural gas properties, with interest payable quarterly, in arrears, at the bank's prime rate. The Company has the option of electing the credit facility or portions thereof to bear interest at the prevailing LIBOR rate plus 1.375%, 1.625%, and 2.000% based on usage of 0-50%, 51%-75%, and 76%-100%, respectively. A 0.375% facility fee on the unused protion of the borrowing base is also paid quarterly. The Company's weighted average interest rate at December 31, 2002 was 3.58%. The note converts to a term loan in February 2004, with the principal payable in equal quarterly installments beginning on February 28, 2004, and continuing through February 28, 2007, based on a five-year amortization of all principal outstanding on February 28, 2004.	$ 95,200,000	$ 84,600,000
Promissory note to an Industrial Development Authority, guaranteed by a letter of credit from a bank, with interest payable monthly based on an interest rate per annum equal to the lesser of the variable rate or highest lawful rate. The average interest rate for 2002 was 1.0%. The note is due and payable on the first Wednesday of June 2026.	1,080,000	1,080,000
Total notes payable	$ 96,280,000	$ 85,680,000

The aggregate maturities of principal on notes payable at December 31, 2002 are $19,040,000 for 2004, $19,040,000 for 2005, $19,040,000 for 2006, $38,080,000 for 2007, and $1,080,000 thereafter.

The current bank credit facility is limited to the lesser of $200.0 million or the borrowing base, which is determined by the banks semiannually based primarily on proved oil and natural gas reserves. At December 31, 2002, the borrowing base was $105.0 million. Under the terms of the loan agreement, the Company is prohibited from incurring additional debt and declaring and paying common stock dividends in excess of $950,000 a year. The transaction to purchase 666,669 shares of the Company's common stock from a converting preferred shareholder received the consent of the banks on December 19, 2000, prior to consummation (see note 11). In addition, the Company's ratio of current assets to current liabilities cannot be less than 1.0 to 1.0 with any unused borrowing base added to current assets. The tangible net worth as of the end of any fiscal quarter commencing with the quarter ending March 31, 1999 cannot be less than $25.0 million, plus 60% of the Company's consolidated net income for each quarter from and after January 1, 1999, in which such net income was positive (quarters in which the Company's consolidated net income was negative shall be disregarded), plus the net proceeds received by the Company for capital stock issued by the Company after March 31, 1999. In addition, earnings before interest, tax, and depreciation (EBITDA) must exceed interest expense by 2.75x on a rolling four-quarter basis. The Company was in compliance with all debt covenants at December 31, 2002 and 2001.

(5) Income Taxes

The Company follows the provisions of SFAS No. 109, *Accounting for Income Taxes*, which provides for recognition of a deferred tax liability or asset for deductible temporary timing differences, operating loss carryforwards, statutory depletion carryforwards, and tax credit carryforwards net of a valuation allowance.

13

The components of income tax expense consist of the following:

	Year ended December 31,		
	2002	**2001**	**2000**
Federal:			
Current	$ (691,748)	$ 772,354	$ 83,821
Deferred	6,499,211	7,567,164	7,586,436
Total federal	5,807,463	8,339,518	7,670,257
State:			
Current	20,570	72,708	128,894
Total state	20,570	72,708	128,894
	$ 5,828,033	$ 8,412,226	$ 7,799,151

A reconciliation of income tax expense to tax at the federal statutory rate is as follows:

	Year ended December 31,		
	2002	**2001**	**2000**
Income before income taxes	$ 16,158,358	$ 23,293,888	$ 22,307,739
Taxes at statutory rate	5,581,429	7,919,922	7,584,631
State income taxes	20,570	72,708	128,894
Amortization of basis difference of oil and natural gas properties	82,103	104,700	94,688
Other	143,931	314,896	(9,062)
Income tax expense	$ 5,828,033	$ 8,412,226	$ 7,799,151

The principal components of the Company's deferred income tax liability are as follows:

	December 31,	
	2002	**2001**

	December 31,	
Deferred income tax assets:		
Net operating loss carryforward	$ 3,053,414	$ 4,251,699
Alternative minimum tax credit carryforward	176,644	868,392
	3,230,058	5,120,091
Deferred income tax liabilities:		
Depreciation, depletion, and amortization	(30,006,142)	(25,355,301)
Other	35,004	(6,659)
	(29,971,138)	(25,361,960)
Net deferred tax liability	$ (26,741,080)	$ (20,241,869)

For tax reporting purposes, the Company had operating loss carryforwards of approximately $9.0 million at December 31, 2002. If not utilized, such carryforwards will begin to expire in 2009 and will completely expire by the year 2019. No valuation allowance has been provided for the deferred tax assets above, as management does not expect the Company's net operating loss carryforwards to expire without being utilized.

(6) Earnings Per Share

Basic and diluted net income per share is computed based on the following information:

	Year ended December 31,		
	2002	2001	2000
Numerator:			
Basic:			
Net income	$ 10,330,325	$ 14,881,662	$ 14,508,588
Preferred stock dividend			(773,409)
Income available to common shareholders	$ 10,330,325	$ 14,881,662	$ 13,735,179
Diluted:			
Net income available to common shareholders	$ 10,330,325	$ 14,881,662	$ 13,735,179
Effect of assumed conversion of preferred stock			773,409
Income available to common shareholders after assumed conversions	$ 10,330,325	$ 14,881,662	$ 14,508,588
Denominator:			
Denominator for basic earnings per share weighted average shares	13,945,986	12,426,197	10,727,622

	Year ended December 31,		
Effect of dilutive securities:			
Preferred stock			2,269,413
Stock options	492,828	596,055	180,882
Dilutive potential common shares	492,828	596,055	2,450,295
Denominator for dilutive earnings per share adjusted weighted average shares and assumed conversion	14,438,814	13,022,252	13,177,917
Basic earnings per share	$ 0.74	$ 1.20	$ 1.28
Diluted earnings per share	0.72	1.14	1.10

(7) Stock Options

The Company has an incentive stock option plan for its key employees that was adopted in 1998 and will remain in effect until 2008. The 1998 Omnibus Stock and Incentive Plan (Option Plan) provides that options may be granted to purchase no more than 1.2 million shares in the aggregate to employees of the Company that are eligible to receive option grants. To date, most options have been granted with a four-year vesting schedule and a ten-year term. All options granted in 2002 have a three-year vesting schedule and a five-year term. The Option Plan also authorizes the granting of stock appreciation rights either in tandem with or independent of the options. These rights allow the optionee to tender vested options and receive the difference between the option price and the price of the Company's common stock at the time of exercise. At the Company's option, these may be paid to the optionee in the equivalent value of common stock or cash. Any stock appreciation rights issued under the Option Plan would be canceled upon the completion of an initial public offering of the Company's common stock and listing on a national exchange. No stock appreciation rights are currently outstanding under the Option Plan and none were outstanding during the years ended December 31, 2002, 2001, and 2000.

In 1998, the Company instituted the NonStatutory Director Stock Option Plan designed to encourage nonemployee directors to participate in the ownership of the Company. The total number of options available for grant under the director stock option plan is 600,000.

Summarized information about the Company's stock option plans is as follows:

	2002		2001		2000	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Outstanding at beginning of year	1,267,940	$ 8.06	892,950	$ 5.52	784,374	$ 5.27
Granted	58,700	13.53	465,785	12.51	157,476	6.40
Exercised	(60,783)	5.18	(45,036)	6.05	(26,400)	3.75
Canceled	(8,801)	10.13	(45,759)	5.68	(22,500)	5.38
Outstanding at end of year	1,257,056	8.44	1,267,940	8.06	892,950	5.52
Exercisable at end of year	864,148	7.40	669,831	6.64	465,876	5.27
Available for grant at end of year	1,108,225		1,158,124		1,579,350	
Weighted average fair value of options granted during the year		2.59		3.44		2.15

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

Options outstanding	Options exercisable

Range of exercise prices	Number outstanding at December 31, 2002	Weighted average remaining contractual life	Weighted average exercise price	Number exercisable at December 31, 2002	Weighted average exercise price
$ 2.33 to 4.00	60,886	4.20	$ 3.56	60,886	$ 3.56
5.47 to 8.33	702,435	7.00	5.80	581,048	5.72
11.67 to 17.00	493,735	8.30	12.75	222,214	12.85
	1,257,056	7.40	8.44	864,148	7.40

During the year ended December 31, 2001, the Company granted 465,785 stock options to employees and directors with exercise prices ranging from $8.33 to $17.00. All options granted to employees vest over four years and all options granted to directors vest immediately. The Company recorded compensation expense of $1,151,997 during the year ended December 31, 2001 related to 428,385 of these options granted between February and June 2001. The expense represents the excess of the estimated fair value of the Company's common stock over the exercise price, recognized over the vesting period of the options. For purposes of determining compensation expense for the options granted between February and June 2001, the Company estimated the fair value of its common stock to be equal to the expected offering price of the Company's common stock in its proposed initial public offering. The Company recorded additional compensation expense of $469,961 during the year ended December 31, 2002 related to these options. As of December 31, 2002, the Company had deferred compensation expense of $381,402, which will be recognized ratably over the remaining related option vesting period.

During the year ended December 31, 2002, the Company granted 58,700 stock options to employees and directors with exercise prices ranging from $13.50 to $17.00. All options granted to employees vest over three years and all options granted to directors vest immediately. All options granted in 2002 were at exercise prices that equaled estimated fair value at grant date.

In April 2002, several managerial employees exercised stock options. Loans of up to 75% of the exercise price of the options were made available to these employees (see note 13). Because the loans were granted interest free, in accordance with FASB Interpretation No. 44, *Accounting for Certain Transactions Involving Stock Compensation*, the exercise price of the options was effectively altered, triggering variable accounting. As such, the Company recorded $257,617 in noncash compensation expense, representing the difference between the fair value of the stock on the date of exercise and the present value of the future cash flow payments from the loans.

(8) Employee Incentive Plans

During April 1997, the Company began a compensation plan (the 1997 Plan) to compensate all eligible employees (those employed by the Company on or before September 1997). The 1997 Plan disbursements were to begin in 2001, and were to be based on achieving certain publicly traded stock price thresholds before January 1, 2001. All award amounts payable under the 1997 Plan could not exceed 5.0% of the total increase in value of the Company to the shareholders from the effective date of April 3, 1997. During 1999, the employees participating in the 1997 Plan were given the option to continue in the 1997 Plan or convert their participation to a revised compensation plan (the Millennium Plan). All participating employees converted to the Millennium Plan, which included a cash bonus equal to 25% of salary as calculated pursuant to the original 1997 Plan to be paid when the Company achieves a public or private stock price of $8.33 per share as determined by the board of directors or public markets. During August 2000, the board of directors determined that such criteria had been met and the cash bonus was paid to participating employees. Consequently, the Company recorded compensation expense during 2000 of $586,216 related to the Incentive Plan.

During the first quarter of 2001, the Company established a share price appreciation plan (the Appreciation Plan) to provide key employees with added incentives to maximize the Company's share price and to attract and retain qualified personnel. The amount of the disbursements will be based on whether the Company achieves a threshold of $16.67 per share of the Company's common stock before January 1, 2004 and maintains such share price for a period of 30 trading days (which need not be consecutive) within 90 consecutive trading days. The compensation committee determines the terms and conditions of each grant, but vesting of awards under the plan is subject to the conditions that (1) the Company completes an initial public offering and be listed and traded on a national or regional stock exchange or on the NASDAQ National Market System, prior to January 1, 2004, or (2) the Company is sold or merged prior to January 1, 2004. The total award amounts payable under the Appreciation Plan cannot exceed 5.0% of the total increase in value of the Company to the shareholders from the effective date of March 1, 2001. It has been determined that this 5.0% limitation will be based upon an assumed price per share of $8.33 as of March 1, 2001. During March 2001, the Company granted an award under the Appreciation Plan, whereby if the conditions above are met, participating employees would immediately receive a bonus payable in cash or common stock at the discretion of the Company, equal to 25% of the participating employees' annual salary. The amount payable under this award if the conditions above are met is approximately $1.2 million.

Upon meeting the vesting conditions, the Company will record compensation expense of approximately $1.2 million in the period such conditions are met. No compensation expense has been recorded for this award as of December 31, 2002, because the vesting conditions have not been met.

(9) Retirement Plan

Effective January 1, 1992, the Company began a defined contribution retirement plan. All Company employees with a minimum of six months of service are eligible. Each employee may contribute between 1% and 15% of annual compensation, up to the maximum allowable amount under the Internal Revenue Code. The board of directors determines the Company's matching contributions. The Company's matched employee compensation amounted to $400,902, $318,784, and $245,810 in 2002, 2001, and 2000, respectively. The Company funded its matching contribution in cash and 24,770 shares of the Company's common stock in 2002, 19,274 shares of common stock in 2001, and 29,496 shares of common stock in 2000. It is anticipated that future company matching contributions will be made in common stock.

(10) Convertible Preferred Stock

During May 1996, the Company sold 388,890 shares of Series A Convertible Preferred Stock (the Preferred Stock) (par value $0.10 per share and liquidation preference and redemption amount of $18.00 per share) for $18.00 per share.

The Preferred Stock was redeemable at the option of the holder beginning in April 2001, unless the Company had completed a qualifying initial public offering on or before May 2000. The Preferred Stock was convertible into the Company's common stock at a $3.00 per common share price at any time prior to redemption and was subject to customary antidilution provisions. Prior to May 2000, the preferred shareholders were entitled to receive a dividend commensurate and concurrent with any per share dividend declared on the Company's common stock. Subsequent to May 2000, the preferred shareholders were entitled to receive an additional dividend at an annual rate of $1.80 per share. During the year ended December 31, 2000, Preferred Stock dividends related to these requirements were $480,281.

On December 22, 2000, all the outstanding Preferred Stock was converted into 2,333,340 shares of the Company's common stock, in accordance with the original conversion terms of the agreement. In connection with the conversion, the Company paid additional preferred dividends of $293,128, representing the discounted value of certain future dividends. All preferred dividends paid on the Preferred Stock during the year ended December 31, 2000 have been deducted in the determination of net income available to common shareholders and for purposes of computing earnings per share for 2000.

(11) Common Stock

(a) Puttable Common Stock

The stock purchase agreement, pursuant to which the Company issued 4,020,000 shares of common stock in 1998 in exchange for oil and natural gas properties acquired from Unocal, gave Unocal the right to put such stock back to the Company for $22.0 million in cash if such put right was not otherwise extinguished pursuant to the terms of the agreement. The put right was first exercisable on January 2, 1999, and if not exercised on such date, the holder had the right to exercise the put option on January 2, 2000. If the put option was not exercised on January 2, 2000, it expired on such date.

The holder of the puttable common stock did not exercise the put option and, accordingly, the put option expired on January 2, 2000.

The Company classified the puttable common stock outside of shareholders' equity for all periods prior to expiration of the put as the ability to extinguish the put was not considered to be completely within the control of the Company. Further, in accordance with the Securities and Exchange Commission rules and regulations, the Company has accreted the difference between the value of the common stock issued in exchange for the oil and natural gas properties to the cash put amount of $22.0 million over the period from the closing date of the purchase transaction (January 20, 1998) to the earliest date the holder had the right to exercise the put (January 2, 1999). Such accretion has been charged to retained earnings in the amount of $4,991,066 in 1998 and $28,934 in 1999, and has been deducted in the determination of net income available to common shareholders for such periods.

(b) Stock Offering

During 2002, the Company sold 2,058,802 shares of common stock in a private offering and received net proceeds of $27,404,600.

(c) Stock Rights

During May 2001, the Company adopted a shareholder rights plan under which it declared a dividend of one common share purchase right for each outstanding share of common stock. The purchase rights entitle shareholders to purchase one share of common stock for an exercise price of $91.67, subject to adjustment. The rights are not immediately exercisable and will generally become exercisable only if a person or group acquires beneficial ownership of 15% or more of the Company's common stock or commences a tender or exchange offer, upon completion of which that person or group would beneficially own 15% or more of the Company's common stock. The rights will become exercisable by holders, other than the unsolicited third-party acquirer, for shares of

the Company or of the third-party acquirer having a value of two times the rights' then-current exercise price. The Company may redeem the rights within ten days of the date on which a person or group acquires more than 15% of the Company's common stock, at a redemption price of $0.01 per right. The rights expire on May 16, 2011, unless otherwise extended.

(d) Treasury Stock

On December 22, 2000, the Company purchased 666,669 shares of common stock at $8.00 per share from a previous holder of the Preferred Stock (see note 10).

On December 29, 2000, the Company contributed 30,213 shares of common stock, issued out of treasury stock, at $8.33 per share to the Company's 401(k) Plan to fund the employer's matching contribution to the Retirement Plan (see note 9) and to certain shareholders for dividend reinvestment.

Also issued out of treasury stock on December 29, 2000, the Company sold 22,200 shares of common stock to employees representing vested stock options exercised during December 2000.

During 2001, the Company purchased 4,378 shares of common stock out of the Matador 401(k) Plan for $26,793, representing the vested shares held in the plan by certain terminated employees. The purchase price of the shares was equal to the most recent fair market value prior to the distribution of proceeds to the former employees.

During 2001, the Company sold 45,036 shares of common stock, issued out of treasury stock, representing vested employee and director stock options exercised during the year.

On December 31, 2001, the Company contributed 19,750 shares of common stock, issued out of treasury stock, at $15.00 per share to the Company's 401(k) Plan to fund a portion of the employer's matching contribution to the Retirement Plan (see note 9) and to certain shareholders for dividend reinvestment.

During 2002, the Company purchased 1,402 shares of common stock out of the Matador 401(k) Plan for $20,768, representing the vested shares held in the plan by certain terminated employees. The purchase price of the shares was equal to the most recent fair market value prior to the distribution of proceeds to the former employees.

During 2002, the Company purchased 7,150 shares of common stock from certain shareholders.

During 2002, the Company sold 62,783 shares of common stock, issued out of treasury stock, representing vested employee and director stock options exercised during the year.

On December 31, 2002 the Company contributed 24,809 shares of common stock, issued out of treasury stock, at $15.00 per share to the Company's 401(k) Plan to fund a portion of the employer's matching contribution to the Retirement Plan (see note 9) and to certain shareholders for dividend reinvestment.

(e) Stock Split

On July 1, 2001, the Company declared a three-for-one split in the form of a stock dividend. All common shares and per common share amounts in the accompanying consolidated financial statements and notes have been restated to retroactively effect this stock split.

(12) Commitments and Contingencies

As of December 31, 2002 and 2001, there were no contingent liabilities or litigation noted or provided for in the consolidated financial statements. From time to time, the Company is a party to litigation; however, there are no pending claims or other circumstances that are expected by management to lead to material litigation or to otherwise have a material impact on the Company's financial condition or results of operations.

The Company leases administrative offices under noncancelable operating leases expiring in 2004. Future minimum lease commitments are $108,108 and $3,206 in 2003 and 2004, respectively. Total rent expense incurred in the years ended December 31, 2002, 2001, and 2000 was $341,787, $282,788, and $213,849, respectively.

(a) General Federal and State Regulation

Oil and natural gas exploration, production, and related operations are subject to extensive federal and state laws, rules, and regulations. Failure to comply with these laws, rules, and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas industry increases the cost of doing business and affects profitability. Because these rules and regulations are frequently amended or reinterpreted, the Company is unable to predict the future cost or impact of complying with these laws.

(b) Environmental Regulation

The exploration, development, and production of oil and natural gas, including the operation of saltwater injection and disposal wells, are subject to various federal, state, and local environmental laws and regulations. These laws and regulations can increase the costs of planning, designing, installing, and operating oil and natural gas wells. The Company's activities are subject to a variety of environmental laws and regulations, including but not limited to: the Oil Pollution Act of 1990, or OPA, the Clean Water Act, or CWA, the Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, the Safe Drinking Water Act, or SDWA, as well as comparable state statutes and regulations. The Company is also subject to regulations governing the handling, transportation, storage, and disposal of naturally occurring radioactive materials, or NORM, that may result from its oil and natural gas operations. Civil and criminal fines and penalties may be imposed for noncompliance with these environmental laws and regulations. Additionally, these laws and regulations require the acquisition of permits or other governmental authorizations before undertaking some activities, limit or prohibit other activities because of protected areas or species, and require investigation and cleanup of pollution. The Company has no outstanding material environmental remediation liabilities and believes that it is in compliance with currently applicable environmental laws and regulations and that these laws and regulations will not have a material adverse impact on the financial position or results of operations of the Company.

(13) Transactions With Related Parties

During 2002, the Company granted interest-free loans to a number of its managerial employees allowing them to purchase additional shares of the Company's common stock. The loans are limited to $250,000 in aggregate outstanding amount and to 75% of the value of shares purchased. As of December 31, 2002, the balance of the loans outstanding was $108,930.

Effective September 5, 2000, the Company entered into an agreement with Unocal in which the Company conveyed to Unocal an undivided 25% working interest in certain leasehold positions in the East Texas Bossier trend in exchange for reimbursement of land, geophysical, geological, and other related costs totaling approximately $3.6 million.

Certain members of the Company's board of directors have invested as working interest owners in some of the wells that the Company has drilled. The wells in which these directors participated were generally the result of the Company's decision, on a well-by-well basis, to sell or farm-out a portion of the working interest in the well to reduce the Company's overall drilling risk level. These directors are billed monthly for expenses, and receive distributions of revenues on the same terms as other, nonaffiliated working interest owners. Since January 1, 1998, the Company drilled and currently operates 14 producing wells that include participation by directors. Except for wells that may be drilled within the existing contract areas of joint operating agreements of prospects in which directors currently hold working interests, the Company expects that no further working interest participation will be offered to directors. The sum of all revenues received by all directors for wells operated by the Company during the year 2002 totaled $430,011. A total of five directors have participated in Matador operated wells, with such participation ranging from 1% to 10% working interest, with an average individual participation of approximately 4%.

(14) Major Customers

During fiscal year 2002, the Company had two customers accounting for 11% and 20% of total revenues. During fiscal year 2001, the Company had three customers accounting for 10%, 12%, and 15% of total revenues. During fiscal year 2000 the Company had one customer accounting for 21% of total revenues. Due to the nature of the markets for oil and natural gas, the Company does not believe that the loss of any one customer would have a material adverse effect on the Company's financial condition or results of operations.

(15) 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 in 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 asset retirement obligations recorded by the Company relate to the plugging and abandonment of gas and oil wells. The Company adopted SFAS No. 143 on January 1, 2003, and recorded a discounted liability of $4.3 million for the future retirement obligation, an increase to property and equipment of $3.0 million and a gain of $0.6 million (net of a deferred tax benefit of $0.3 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 other than additional asset retirement obligation of $0.2 million for wells drilled. Accretion expense of $0.1 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.

			Year Ended					
		Three Months Ended March 31, 2002		**December 31, 2002**		**December 31, 2001**		**December 31, 2000**
Net (loss) income								
As reported	$	321,631	$	10,330,325	$	14,881,662	$	14,508,588
Accretion of retirement obligation (net of tax)		(58,269)		(233,078)		(213,833)		(196,177)
Reduction of depreciation and depletion (net of tax)		63,394		253,574		332,010		350,945
Pro forma	$	326,756	$	10,350,821	$	14,999,839	$	14,663,356
Basic net income (loss) per common share:								
As reported	$	0.03	$	0.74	$	1.20	$	1.28
Pro forma	$	0.03	$	0.74	$	1.21	$	1.29
Diluted net income (loss) per common share:								
As reported	$	0.03	$	0.72	$	1.14	$	1.10
Pro forma	$	0.03	$	0.72	$	1.15	$	1.11

(16) Events Subsequent to Date of Independent Auditor's Report (Unaudited)

In March 2003 the bank credit facility was amended. The amendment extended the final maturity date to February 28, 2008 and the conversion date to a term loan from February 28, 2004 to February 28, 2005. The borrowing base was also increased to $115 million.

On May 14, 2003, a definitive merger agreement between the Company and Tom Brown, Inc., a Denver, Colorado based independent energy company, was executed. Tom Brown, Inc. agreed to acquire all of the outstanding shares of the Company for $17.53 per share and all outstanding options at $17.53 per option share less the exercise price of the options. Tom Brown also agreed to assume all outstanding debt. The boards of both companies approved the acquisition and the transaction closed on June 27, 2003.

(17) Supplemental Information Related to Oil and Natural Gas Exploration, Development, and Production Activities

The following tables set forth certain historical costs and operating information related to the Company's oil and natural gas producing activities as of and for the years ended December 31, 2002, 2001, and 2000:

(a) Costs Incurred

Costs incurred in oil and natural gas property acquisition, exploration, and development activities are summarized below:

	December 31,		
	2002	**2001**	**2000**
Property acquisition costs:			
Proved, excluding deferred income taxes	$ 3,389,091	$ 4,756,245	$ 6,375,320
Exploration costs	7,557,721	28,521,259	9,304,953
Development costs	67,586,971	38,055,331	29,244,225
Total costs incurred	$ 78,533,783	$ 71,332,835	$ 44,924,498

(b) Oil and Natural Gas Reserves (Unaudited)

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

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

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

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

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

The Company's net ownership in estimated quantities of proved oil and natural gas reserves and changes in net proved reserves are summarized below:

	Gas (Mmcf)	Oil (Mbbls)
Proved reserves at December 31, 1999	69,049	5,698
Revisions of estimates	640	(405)
Improved recovery	14	33
Extensions and discoveries	36,950	822
Purchase of reserves	13,723	229
Sale of reserves	(105)	(110)
Production	(8,373)	(554)
Proved reserves at December 31, 2000	111,898	5,713
Revisions of estimates	(7,439)	(9)
Improved recovery	9	11
Extensions and discoveries	66,668	960
Purchase of reserves	8,731	22
Sale of reserves	(18)	(13)
Production	(11,822)	(755)
Proved reserves at December 31, 2001	168,027	5,929
Revisions of estimates	(13,593)	(535)
Improved recovery	40	199
Extensions and discoveries	95,404	2,252
Purchase of reserves	3,414	40
Production	(15,130)	(648)
Proved reserves at December 31, 2002	238,162	7,237
Proved developed reserves at:		
December 31, 2000	89,446	5,145
December 31, 2001	108,452	5,260
December 31, 2002	133,614	5,352

Standardized Measure (Unaudited)

The standardized measure of discounted future net cash flows relating to the Company's proved reserves as of year-end is shown below:

	December 31,		
	2002	2001	2000
Future cash flows	$ 1,279,884,973	$ 511,735,030	$ 1,214,431,163
Future production costs	(276,037,244)	(129,536,419)	(193,500,966)
Future development costs	(107,250,657)	(56,692,979)	(25,886,677)

	December 31,		
Future net cash flows before taxes	896,597,072	325,505,632	995,043,520
Future income taxes	(233,146,222)	(69,035,539)	(292,706,451)
Future net cash flows after taxes	663,450,850	256,470,093	702,337,069
Annual discount at 10%	(345,689,805)	(127,253,937)	(357,837,172)
Standardized measure of discounted future cash flows	$ 317,761,045	$ 129,216,156	$ 344,499,897

The average prices for oil and natural gas used to calculate future cash inflows at December 31, 2002, 2001, and 2000 were $30.32, $18.78, and $25.92 per Bbl and $4.54, $2.38, and $9.53 per Mcf, respectively. Future cash flows are computed by applying year-end prices of oil and natural gas to year-end quantities of proved oil and natural gas reserves. Future operating expenses, including overhead costs attributable to producing activities, and development costs are computed primarily by the Company's petroleum engineers by estimating the expenditures to be incurred in developing and producing the Company's proved oil and natural gas reserves at the end of the year, based on the year-end costs and assuming continuation of existing economic conditions. Future income taxes are based on year-end statutory rates. A discount factor of 10% was used to reflect the timing of future net cash flows. The standardized measure of discounted future net cash flows is not intended to represent the replacement cost or fair market value of the Company's oil and natural gas properties. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs, and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

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

	Proved Undeveloped	Proved Developed Non-producing
2003	$ 38,481	$ 1,639
2004	$ 32,241	$ 787
2005	$ 20,489	$ 188

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Changes in Standardized Measure (Unaudited)

Changes in standardized measure of future net cash flows relating to proved oil and natural gas reserves are summarized below:

	December 31,		
	2002	2001	2000
Standardized measure, beginning of year	$ 125,903,156	$ 341,186,897	$ 85,987,724
Oil and natural gas sales, net of production costs	(46,409,676)	(50,761,568)	(39,936,423)
Net change in prices and production costs	147,840,779	(400,957,208)	203,387,036
Extensions, discoveries, additions, and improved recovery, less related costs	152,611,776	43,705,406	150,815,048
Previously estimated development costs incurred during period	20,853,072	15,557,689	7,164,688
Revision of quantity estimates	(25,474,719)	(5,835,523)	(6,071,011)
Purchases of minerals in place	6,173,403	7,442,289	13,745,110
Sales of minerals in place		(227,800)	(2,592,317)
Accretion of discount	15,856,284	49,671,263	10,891,628
Net change in income taxes	(79,846,562)	122,867,051	(132,597,175)
Changes due to timing and other	(3,059,468)	3,254,660	50,392,589
Standardized measure, end of year	$ 314,448,045	$ 125,903,156	$ 341,186,897

December 31,

Sales of oil and natural gas, net of production costs, are based on historical pretax results. All other amounts are reported on a pretax discounted basis.

The actual costs incurred for the development of proved undeveloped and proved non-producing properties were as follows (in thousands):

	Proved Undeveloped	Proved Developed Non-producing	Total
2000	$ 8,772	$ 2,397	$ 11,169
2001	13,541	1,886	15,427
2002	19,733	706	20,439

Tom Brown, Inc.

PRO FORMA FINANCIAL INFORMATION

On May 14, 2003, Tom Brown, Inc. ("Tom Brown" or the "Company") entered into an agreement to acquire all of the outstanding common stock of Matador Petroleum Corporation ("Matador"). Matador is an independent energy company based in Dallas, Texas engaged in oil and gas exploration, production, development and acquisition activities in the Southwestern United States. Approximately 85 percent of Matador's reserves are natural gas and Matador's primary focus has been the East Texas Basin and the Permian Basin of West Texas and Southeastern New Mexico.

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

In connection with the transaction, three officers of Matador entered into non-compete agreements with Tom Brown, for periods ranging from 3 to 21 months for aggregate consideration of $4.7 million.

The following unaudited pro forma condensed combined financial information shows the pro forma effect of the 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 three months ended March 31, 2003, which assume the acquisition occurred on January 1, 2002. The unaudited pro forma condensed combined financial information also includes a pro forma balance sheet as of March 31, 2003, which assumes the acquisition occurred on that date.

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 Balance Sheet

March 31, 2003

	Tom Brown, Inc. Historical	Matador Historical	Pro Forma Adjustments (Note 3)	Pro Forma Combined Company
	(In thousands)			
Assets				
Current assets				
Cash and cash equivalents	$ 18,269	$ 3,433	$	$ 21,702
Accounts receivable	75,785	24,180		99,965
Prepaid expenses and other	5,071	729		5,800
Total currents assets	99,125	28,342		127,467
Property and equipment, at cost	1,148,084	344,822	41,304(a)	1,534,240
Less: Accumulated depreciation and depletion	340,274	89,359	89,359(a)	340,274
Net property and equipment	807,810	255,463	130,663	1,193,936
Goodwill, intangible assets and other	7,290	668	4,791(f) 87,970(a)	100,719
	$ 914,225	$ 284,473	$ 223,424	$ 1,422,122
Liabilities and stockholders' Equity				
Current liabilities				
Accounts payable and accrued expenses	$ 75,536	$ 26,112	$ 19,824(a)(f)	$ 121,472
Current portion of bank debt	34,360			34,360
Fair value of derivative instruments	16,680			16,680
Total current liabilities	126,576	26,112	19,824	172,512
Bank debt	100,881	107,480	277,573(a)	485,934
Deferred income taxes	85,055	33,277	38,508	156,840
Other non-current liabilities	20,635	4,523	600(f)	25,758
Total stockholders' equity	581,078	113,081	(113,081)(a)	581,078
	$ 914,225	$ 284,473	$ 223,424	$ 1,422,122

See Notes to Unaudited Pro Forma Condensed Combined Financial Statements.

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Tom Brown, Inc.

Unaudited Pro Forma Condensed Statement of Operations

Three Months Ended
March 31, 2003

	Tom Brown, Inc. Historical	Matador Historical	Pro Forma Adjustments (Note 3)	Pro Forma Combined Company
	(In thousands)			
Revenues				
Gas and oil sales	$ 80,480	$ 31,596	$	$ 112,076
Gathering and processing	6,076			6,076
Marketing and trading, net	13,854			13,854
Other	3,628	45		3,673
Total revenues	104,038	31,641		$ 135,679
Costs and expenses				
Gas and oil production	8,185	2,926		11,111
Taxes on gas and oil production	6,538	2,068		8,606
Trading	13,141			13,141
Gathering and processing costs	2,034			2,034
Cost of drilling operations	2,934			2,934
Exploration costs	6,874		831(c)	7,705
Impairments of leasehold costs	1,474		150(e)	1,624
General and administrative	4,847	1,710	692(c)	7,249
Depreciation, depletion, and amortization	21,417	5,833	1,421(d)	28,671
Accretion	292	96		388
Bad debt	152			152
Amortization of non-compete agreements			538(f)	538
Interest expense and other	3,556	914	4,247(b)	8,717
Total costs and expenses	71,444	13,547	7,879	92,870
Income before income taxes and cumulative effect of change in accounting principle	32,594	18,094	(7,879)	42,809
Income tax provision	(11,797)	(6,237)	2,757(g)	(15,277)
Income before cumulative effect of change in accounting principle	$ 20,797	$ 11,857	$ (5,122)	$ 27,532
Weighted average number of common shares outstanding	40,442			40,442
Net income before cumulative effect of change in accounting principle per common share	$ 0.49			$ 0.68

See Notes in Unaudited Pro Forma Condensed Combined Financial Statements.

Tom Brown, Inc.
Unaudited Pro Forma Condensed Statement of Operations

Year Ended
December 31, 2002

	Tom Brown, Inc. Historical	Matador Historical	Pro Forma Adjustments (Note 3)	Pro Forma Combined Company
		(In thousands)		
Revenues				
Gas and oil sales	$ 194,276	$ 59,936	$	$ 254,212
Gathering and processing	20,467			20,467
Marketing and trading, net	5,276			5,276
Drilling	14,347			14,347
Gain on sale of property	4,114			4,114
Cash paid on derivatives	(2,061)			(2,061)
Change in derivative fair value	(345)			(345)
Loss on marketable security	(600)			(600)
Interest income and other	171	268		439
Total revenues	235,645	60,204		295,849
Costs and expenses				
Gas and oil production	32,151	8,586		40,737
Taxes on gas and oil production	16,621	4,940		21,561
Gathering and processing costs	6,918			6,918
Cost of drilling operations	13,763			13,763
Exploration costs	22,824		3,493(c)	26,317
Impairments of leasehold costs	5,564		588(e)	6,152
General and administrative	18,413	6,550	2,375(c)	27,338
Depreciation, depletion, and amortization	91,307	20,766	4,666(d)	116,739
Bad debt	5,222			5,222
Amortization of non-compete agreements			3,176(f)	3,176
Interest expense and other	9,726	3,202	16,988(b)	29,916
Total costs and expenses	222,509	44,044	31,286	297,839
Income (loss) before income taxes and cumulative effect of change in accounting principle	13,136	16,160	(31,286)	(1,990)
Income tax (provision) benefit	(3,210)	(5,828)	10,950(g)	1,912
Income (loss) before cumulative effect of change in accounting principle	$ 9,926	$ 10,332	$ (20,336)	$ (78)
Weighted average number of common shares outstanding	40,327			40,327
Income (Loss) before cumulative effect of change in accounting principle per common share	$ 0.25			$

See Notes to Unaudited Pro Forma Condensed Combined Financial Statements.

Tom Brown, Inc.

NOTES TO UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL INFORMATION

(1) BASIS OF PRESENTATION

The accompanying unaudited pro forma condensed combined balance sheet and condensed combined statements of operations present the pro forma effects of the acquisition. The unaudited pro forma condensed combined balance sheet is presented as though the acquisition occurred on March 31, 2003. The unaudited pro forma condensed combined statements of operations for the three months ended March 31, 2003 and the year ended December 31, 2002 are presented as though the acquisition occurred on January 1, 2002.

(2) METHOD OF ACCOUNTING FOR THE ACQUISITION

Tom Brown will account for the acquisition using the purchase method of accounting for business combinations. Under this method of accounting, Tom Brown is deemed to be the acquirer for accounting purposes. Matador's assets and liabilities will be 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 balance sheet and statements of operations include the following adjustments:

(a) The purchase price adjustment in the balance sheet restates the historical values of Matador's assets and liabilities to their estimated fair values as of March 31, 2003. The calculation of the total purchase price and the preliminary allocation of this price to the acquired assets and liabilities are shown below (in thousands):

	Elimination of Matador Historical	Preliminary Purchase Price	Purchase Price Allocation	Net Pro Forma Adjustment
Current Assets	$ 28,342	$	$ 28,342	$
Property and equipment, at cost	344,822		386,126	41,304
Accumulated depreciation and depletion	(89,359)			89,359
Goodwill and other	668		88,638	87,970
	$ 284,473	$	$ 503,106	$ 218,633
Current liabilities	$ 26,112	$ 41,145	$	$ 15,033
Long-term debt	107,480	385,053		277,573
Deferred income taxes	33,277	71,785		38,508
Other non-current liabilities	4,523	5,123		600
Stockholder' equity	113,081			(113,081)
	$ 284,473	$ 503,106	$	$ 218,633

The following table reflects the calculation of the preliminary purchase price for Matador (in thousands):

Current liabilities assumed	$ 41,145

Long-term debt of Matador assumed	107,480
Incremental borrowings by Tom Brown	277,573
Deferred income taxes	71,785
Other non-current liabilities assumed	5,123
	$ 503,106

The total preliminary purchase price includes the anticipated acquisition cost to acquire all of the outstanding common stock of Matador. Shareholders received a net price of $17.53 per common share and option holders received $17.53 per option share less the exercise price of the options or a total of

$267 million. In addition to the amount paid for the common shares and the debt assumed by Tom Brown, the purchase price includes:

Transaction related merger costs of approximately $6.0 million. These costs include investment banking expenses, legal, accounting and other direct merger-related costs.

Additional costs incurred related to the transaction included $7.7 million incurred for payments made to officers and employees of Matador pursuant to a change in control arrangement previously entered into by Matador and $1.3 million incurred for payments made to Matador employees under the terms of a stock appreciation plan, which provided for payments in the event of a change in control of Matador. Compensation of employees who are employed during the transition period along with stay bonuses payable to those employees will be expensed in the period subsequent to the acquisition.

Matador's accounting policy has been to recognize gas sales as income when received in cash. Tom Brown has historically recognized gas revenues under the entitlement method whereby revenues are recognized as the Company's entitlement share of gas is produced based upon its working interests in the gas properties. Under this method, a receivable (payable) is recorded, to the extent the Company receives less (more) than its proportionate share of the revenues from the gas produced. At March 31, 2003, an adjustment of approximately $600,000 was recorded as a long-term liability to recognize the net unrecorded gas imbalance liability for Matador. The impact of the gas imbalances on the revenues recognized for the year ended December 31, 2002 and three months ended March 31, 2003 was not significant.

The other non-current liability of Matador assumed represents the asset retirement obligation accounted for under Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations." Matador and Tom Brown adopted SFAS No. 143 effective January 1, 2003 by recording a cumulative effect adjustment to recognize transition amounts for asset retirement obligations.

Tom Brown estimated the fair value of Matador's current assets, other assets, current liabilities and other non-current liabilities to be equivalent to Matador's historical net book value. Real estate was adjusted to an estimate of its current market value. The gas and oil properties were valued based upon proved gas and oil reserve valuations prepared in conjunction with the acquisition and an internal appraisal was made of the undeveloped leasehold interests of Matador.

The allocation of the purchase price to the Matador assets resulted in a difference between the book and tax basis of the Matador assets of approximately $214 million. Based upon an effective tax rate of 35 percent, deferred income taxes were recognized to the extent that the offsetting increase in the cost basis assigned to the gas and oil properties did not exceed the value of the proved reserves. This limitation resulted in the recognition of approximately $84 million of goodwill in conjunction with the acquisition.

(b) Interest expense increased as a result of Tom Brown borrowing approximately $278 million in conjunction with the acquisition. Of this amount, $155 million was advanced from a recently negotiated senior subordinated credit facility and the balance of the funding was provided under a new revolving 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) Adjustment were required to expense certain items under the successful efforts method of accounting utilized by Tom Brown 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 which 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 Tom Brown in conjunction with the transaction. One contract covered 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 contract. The other two contracts were for terms of three months in exchange for $0.5 million each which was paid at closing. A pro forma adjustment has been recorded to reflect the expense associated with these contracts over the terms of the agreements assuming the agreements were entered into on January 1, 2002.

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

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

The Company has 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 companies. The issue is whether the provisions of SFAS No. 141 and SFAS No. 142 require registrants to classify costs associated with mineral rights, including both proved and unproved lease acquisition costs, as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs.

Historically, Tom Brown 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 registrants 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 Tom Browns capitalized oil and gas property costs and a substantial portion of the acquisition costs attributable to the Matador properties acquired would be separately classified in the pro forma balance sheet as intangible assets.

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.

(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 Tom Brown, Matador and the combined company on a pro forma basis for the year ended December 31, 2002.

	Total			United States			Canada
	Tom Brown	Matador	Combined	Tom Brown	Matador	Combined	Tom Brown
	(In thousands)						
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	1,414
Exploration costs	35,035	7,558	42,593	32,482	7,558	40,040	2,553
Development costs	94,567	65,137	159,704	85,319	65,137	150,456	9,248
Total	$ 154,495	$ 76,084	$ 230,579	$ 141,280	$ 76,084	$ 217,364	$ 13,215

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

	Total			United States			Canada
Natural Gas	Tom Brown	Matador	Combined	Tom Brown	Matador	Combined	Tom Brown
	(Mmcf)						
Proved reserves:							
Estimated reserves at December 31, 2001	641,579	168,027	809,606	582,052	168,027	750,079	59,527
Revisions of previous estimates	10,913	(13,593)	(2,680)	8,304	(13,593)	(5,289)	2,609
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	4,791
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)	(6,386)
Estimated reserves at December 31, 2002	674,027	238,162	912,189	613,496	238,162	851,658	60,541
Proved developed reserves:							
December 31, 2002	507,422	133,614	641,036	481,183	133,614	614,797	56,239

	Total			United States			Canada
Oil	Tom Brown	Matador	Combined	Tom Brown	Matador	Combined	Tom Brown

	Total			United States			Canada
				(Mbbls)			
Proved reserves:							
Estimated reserves at December 31, 2001	6,647	5,929	12,576	5,469	5,929	11,398	1,178
Revisions of previous estimates	898	(535)	363	580	(535)	45	318
Purchases of minerals in place	34	40	74	34	40	74	
Extensions and discoveries	451	2,451	2,902	193	2,451	2,644	258
Sales of minerals in place	(1,162)		(1,162)	(1,162)		(1,162)	
Production	(843)	(648)	(1,491)	(623)	(648)	(1,271)	(220)
Estimated reserves at December 31, 2002	6,025	7,237	13,262	4,491	7,237	11,728	1,534
Proved developed reserves:							
December 31, 2002	4,551	5,352	9,903	3,299	5,352	8,651	1,252

	Total			United States			Canada
Natural Gas Liquids	**Tom Brown**	**Matador**	**Combined**	**Tom Brown**	**Matador**	**Combined**	**Tom Brown**
				(Mbbls)			
Proved reserves:							
Estimated reserves at December 31, 2001	8,360		8,360	6,634		6,634	1,726
Revisions of previous estimates	(628)		(628)	(956)		(956)	328
Purchases of minerals in place							
Extensions and discoveries	305		305	186		186	119
Sales of minerals in place							
Production	(1,382)		(1,382)	(1,189)		(1,189)	(193)
Estimated reserves at December 31, 2002	6,655		6,655	4,675		4,675	1,980
Proved developed reserves:							
December 31, 2002	5,825		5,825	4,002		4,002	1,823

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The following tables set forth the standardized measure of discounted future net cash flows relating to proved oil, natural gas and natural gas liquids reserves for Tom Brown, Matador and the combined company on a pro forma basis as of December 31, 2002.

	Total			United States			Canada
	Tom Brown	**Matador**	**Combined**	**Tom Brown**	**Matador**	**Combined**	**Tom Brown**
				(In thousands)			

	Total			United States			Canada
Future cash flows	$ 2,570,168	$ 1,279,885	$ 3,850,053	$ 2,243,751	$ 1,279,885	$ 3,523,636	$ 326,417
Future production costs	(799,637)	(279,350)	(1,078,987)	(732,739)	(279,350)	(1,012,089)	(66,898)
Future development costs	(186,363)	(107,251)	(293,614)	(175,085)	(107,251)	(282,336)	(11,278)
Future net cash flows before tax	1,584,168	893,284	2,477,452	1,335,927	893,284	2,229,211	248,241
Future income taxes	(451,706)	(233,146)	(684,852)	(367,271)	(233,146)	(600,417)	(84,435)
Future net cash flows after tax	1,132,462	660,138	1,792,600	968,656	660,138	1,628,794	163,806
Annual discount at 10%	(468,454)	(345,690)	(814,144)	(405,487)	(345,690)	(751,177)	(62,967)
Standardized measure of discounted future net cash flows	$ 664,008	$ 314,448	$ 978,456	$ 563,169	$ 314,448	$ 877,619	$ 100,839
Discounted future net cash flows before income taxes	$ 883,353	$ 426,114	$ 1,309,467	$ 744,608	$ 426,114	$ 1,170,722	$ 138,745

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

	Total			United States			Canada
	Tom Brown	Matador	Combined	Tom Brown	Matador	Combined	Tom Brown
				(In thousands)			
Gas and oil sales, net production costs(1)	$ (145,504)	$ (46,410)	$ (191,914)	$ (122,574)	$ (46,410)	$ (168,984)	$ (22,930)
Net changes in anticipated prices and production costs	325,690	147,841	473,531	265,587	147,841	413,428	60,103
Extension and discoveries, less related costs	112,018	152,612	264,630	95,798	152,612	248,410	16,220
Changes in estimated future development costs	(1,813)		(1,813)	2,752		2,752	(4,565)
Previously estimated development costs incurred	39,406	20,853	60,259	37,124	20,853	57,977	2,282
Net change in income taxes	(170,753)	(79,847)	(250,600)	(140,036)	(79,847)	(219,883)	(30,717)
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	7,138
Revision of quantity estimates	19,147	(25,474)	(6,327)	7,586	(25,474)	(17,888)	11,561
Changes in production rates and other	(22,594)	(3,059)	(25,653)	(20,148)	(3,059)	(23,207)	(2,446)
Change in Standardized Measure	$ 211,312	$ 188,545	$ 399,857	$ 174,666	$ 188,545	$ 363,211	$ 36,646

(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.

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 hereunto duly authorized.

Date: August 1, 2003

TOM BROWN, INC.

By: /s/ DANIEL G. BLANCHARD

Daniel G. Blanchard
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

By: /s/ RICHARD L. SATRE

Richard L. Satre
Controller
(Principal Accounting Officer)

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