BROWN TOM INC /DE
Form 8-K
August 08, 2003

SECURITIES AND EXCHANGE

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the

Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) **August 7, 2003**

Tom Brown, Inc.

(Exact name of registrant as specified in its charter)

DELAWARE	**001-31308**	**95-1949781**
(STATE OR OTHER JURISDICTION OF INCORPORATION OR ORGANIZATION)	(Commission File Number)	(I.R.S. EMPLOYER IDENTIFICATION NO.)

555 SEVENTEENTH STREET, SUITE 1850 **DENVER, COLORADO**	**80202**
(ADDRESS OF PRINCIPAL EXECUTIVE OFFICES)	(ZIP CODE)

(303) 260-5000

(REGISTRANT S TELEPHONE NUMBER, INCLUDING AREA CODE)

NOT APPLICABLE

(FORMER NAME, FORMER ADDRESS AND FORMER FISCAL YEAR,

IF CHANGED SINCE LAST REPORT)

ITEM 12. RESULTS OF OPERATIONS AND FINANCIAL CONDITION.

Tom Brown, Inc. press release dated August 7,2003, entitled

TOM BROWN, INC. REPORTS SECOND QUARTER 2003 FINANCIAL AND OPERATING RESULTS

SIGNATURE

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 8, 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)

ITEM 12. RESULTS OF OPERATIONS AND FINANCIAL CONDITION.

The Company issued the following press release:

TOM BROWN, INC.

REPORTS SECOND QUARTER 2003 FINANCIAL AND OPERATING

RESULTS

DENVER, August 7, 2003 Tom Brown, Inc. (NYSE:TBI) today reported results from operations for the second quarter ended June 30, 2003. The Company reported net income for the three months ended June 30, 2003 of $21.4 million or $0.53 per share (all per share amounts are on a diluted basis) compared to $4.8 million or $0.12 per share in the second quarter of 2002. The Company reported income before the cumulative effect of changes in accounting principles for the six months ended June 30, 2003 of $42.2 million or $1.04 per share as compared to $4.4 million or $0.11 per share for the comparable period of 2002.

Discretionary cash flow for the second quarter of 2003 totaled $59.9 million (see reconciliation below to net cash provided by operating activities of $48.6 million), an increase of 63% from $36.8 million in the corresponding period of 2002. Discretionary cash flow for the six months ended June 30, 2003 totaled $122.3 million as compared to $63.4 million for the comparable period of the prior year. The majority of the increase in earnings and discretionary cash flow is attributable to higher natural gas and oil prices.

As previously announced, the Company closed the acquisition of Matador Petroleum Corporation on June 27, 2003 and the results related to the acquired assets will be included in the Company s results of operations beginning in the third quarter of 2003. The balance sheet at June 30, 2003, however, does reflect the effect of the purchase in this quarter. This acquisition will increase Tom Brown s proved reserves by an estimated 269 billion cubic feet equivalent (Bcfe) to approximately 1.02 trillion cubic feet equivalent (Tcfe). The Matador properties are primarily located in the East Texas and Permian Basins.

Tom Brown, Inc. s Chairman, CEO and President, Jim Lightner, commented that, Our second quarter results were on track with our expectations due to the successful execution of our drilling programs. After a challenging year in 2002, when Rockies natural gas prices averaged less than $2.00 and a slow first quarter due to seasonal drilling restrictions, our development drilling projects are ramping up. This increased activity should result in approximately 14% growth in production from the first quarter through the fourth quarter of 2003 excluding the Matador acquisition. Our exploration drilling program was very active in the first half of 2003 and we are encouraged with the results on a number of wells tested to date. Finally, we are very excited by our Matador Petroleum acquisition and the opportunity it provides. Matador s properties will significantly add to the depth of our drilling portfolio and we gained a seasoned team of dedicated and talented people. Coupled with our proven exploration and exploitation capabilities, these assets should provide significant long-term growth opportunities for our shareholders.

The following table summarizes the Company s production and commodity price realizations for the 2003 and 2002 periods ended June 30:

	Three Months Ended			**Six Months Ended**		
	6/30/03	**6/30/02**	**Change**	**6/30/03**	**6/30/02**	**Change**
Production						
Natural gas (Bcf)	17.0	18.7	9%	33.8	36.6	8%
Oil (MBbls)	208.6	220.5	5%	388.9	455.4	15%
NGLs (MBbls)	368.2	378.1	3%	746.8	725.2	3%
Equivalent (Bcfe)	20.4	22.3	9%	40.6	43.7	7%
Realized Prices*						-
Natural gas ($/Mcf)	3.90	2.36	65%	3.97	2.13	86%
Oil ($/Bbl)	27.14	23.70	15%	28.80	21.45	34%
NGLs ($/Bbl)	17.82	10.86	64%	18.31	9.77	88%

*Includes effects of hedging.

Second quarter 2003 production averaged 224.5 million cubic feet equivalent per day (Mmfepd), an 8% decrease over the comparable period of 2002. The second quarter 2003 production was impacted by reduced drilling activities beginning in the second half of 2002, as a result of low natural gas prices in the Rocky Mountain region and the first quarter of 2003 seasonal drilling restrictions. Gas, oil and natural gas liquids sales for the three months ended June 30, 2003 totaled $78.5 million, an increase of $25.1 million, or 47%, from the prior year s comparable period due to higher commodity prices in the current quarter.

Production expense for the most recently completed quarter and the comparable prior year s quarter averaged $0.42 per Mcfe and $0.37 per Mcfe, respectively, while production taxes of $0.35 per Mcfe in the most recently completed quarter were $0.22 per Mcfe higher than in the corresponding period of the prior year. The increase in production taxes is a result of higher commodity prices. Combined cash costs (production expense, production taxes, interest expense and general and administrative) totaled $1.16 per Mcfe in the second quarter of 2003, $0.25 per

Mcfe higher than in the prior year s comparable period. Net cash margin (revenues less combined cash costs) totaled $2.68 per Mcfe in the most recently completed quarter as compared to $1.49 per Mcfe in the prior year s comparable period.

The Company s marketing, trading, gathering and processing margins (revenues less combined costs) totaled $3.1 million in the most recently completed quarter compared to $4.3 million in the corresponding period in the prior year. The marketing and trading margin for the second quarter of 2003 was $0.3 million as compared to $1.3 million in the prior year s second quarter. The marketing and trading margin is lower in the most recent quarter primarily because the spread between Rockies and Mid-Continent basis differentials was tighter in this year s quarter compared to last year s resulting in a reduced margin on the firm transportation held by the Company. The gathering and processing margin was $2.8 million for the second quarter of this year as compared to $3.0 million for the previous year s second quarter primarily due to reduced gathering volumes.

2003 Exploration and Development Program

For the six months ended June 30, 2003, the Company drilled or participated in a total of 65 wells in the U.S. and eight in Canada. Of the 65 wells drilled in the U.S., as of June 30, 2003, 46 wells had been completed, 16 wells were in the process of being completed and three were abandoned. Of the eight wells drilled in Canada, at June 30, 2003 four wells had been completed and four wells were in the process of being completed. Including the Matador properties, as of June 30, 2003, Tom Brown had 15 operated wells drilling in the U.S. and two in Canada.

Wind River Basin

For the six months ended June 30, 2003, the Company drilled ten gross wells in the Wind River Basin of which eight of the wells were at Frenchie Draw field. The two wells drilled outside of Frenchie Draw field are exploratory wells; Blazing Saddles 33-32 (TBI 80% working interest) and Curly 10-22 (TBI 25% working interest). These exploratory wells were drilled to total depths in the range of 8,000-14,000 feet and are currently being completed and tested. The Company produced an average of 52.0 Mmcfepd net for the six months ended June 30, 2003 from the Wind River Basin as compared to 63.7 Mmcfepd in the comparable period of the prior year. This production decline was due to reduced drilling activity in the Basin. There was no drilling activity in the second quarter on the Wind River Indian Reservation due to finalization of certain contractual issues with the Northern Arapahoe and Eastern Shoshone Indian tribes.

Greater Green River Basin

In the first six months of 2003, the Company drilled six gross wells in the Greater Green River Basin. Of note the CEPO Lewis 22-18 (TBI 30% working interest) had an initial production rate of 6.5 Mmcfepd and has been on sales since the early part of the second quarter and is currently producing at 5.7 Mmcfepd. The Gamblers Reservoir 43-32 (TBI 50% working interest) exploratory well has been completed and tested at 1.9 Mmcfepd and is currently waiting on pipeline hookup.

Piceance Basin

The Company drilled ten gross wells in the first six months of 2003 in the Piceance Basin. All of this drilling occurred in the second quarter principally in the White River Dome field. No wells were drilled in the Piceance in the first quarter of 2003 due to seasonal restrictions. The Pallaoro 23-12H (TBI 100% working interest), a horizontal exploratory well testing the Corcoran formation, had an initial production rate of approximately 850 Mcfepd. Further production history is needed to determine the significance of this completion. The Company produced an average of 28.6 Mmcfepd net for the six months ended June 30, 2003 from the Piceance Basin as compared to 33.6 Mmcfepd in the comparable period of the prior year.

Paradox Basin

The Company drilled six gross wells in the Paradox Basin in the first half of 2003 primarily in the Andy s Mesa and Hamilton Creek fields. The Maverick Draw (TBI 59.7% working interest) exploratory well has been completed and is currently testing. The Company produced an average of 50.1 Mmcfepd net for the six months ended June 30, 2003 as compared to 46.1 Mmcfepd in the comparable period of the prior year.

Southern Region (Permian and East Texas Basins)

In the first six months of the 2003, the Company drilled or participated in 33 gross wells in the Southern Region and five wells were drilling at quarter-end. The Company produced an average of 45.7 Mmcfepd net for the six months ended June 30, 2003 from the Southern Region as compared to 49.1 Mmcfepd in the comparable period of the prior year. In the Mimms Creek field (TBI 55% working interest) in the East Texas Basin, the Company participated in eight wells in the first half of 2003.

In the Deep Valley project area in the Permian Basin, the Company completed drilling the horizontal re-entry of the Frost #3 (TBI 37.5% working interest) which had an initial production rate of 10 Mmcfepd and is currently producing at 5 Mmcfepd. This well is near the Trees Estate #4H, the Company s previously announced discovery.

Canada

In the first six months of 2003, the Company drilled eight wells in Canada primarily in the Carrot Creek and Edson fields. The Company produced an average of 24.2 Mmcfepd net for the six months ended June 30, 2003 as compared to 24.7 Mmcfepd in the comparable period of the prior year. Of note, the Company recently flow-tested the Whitehorse well (TBI 100% working interest) which flowed at 3.1 Mmcfpd, and will be tied into our Carrot production facilities in the third quarter of 2003.

Outlook for 2003

The following statements provide a summary of certain estimates for the third quarter and full-year of 2003 based on current expectations and the projected impact of the Matador acquisition beginning on July 1, 2003. Tom Brown s exploration and development capital expenditures (excluding acquisitions) for the first six months of 2003 totaled $73.7 million. For the full-year 2003, the Company is forecasting exploration and development capital expenditures in the range of $245-$255 million (excluding the cost to acquire Matador), which includes approximately 70%-75% for development activities and the remainder for land acquisitions and exploration.

Based upon this anticipated range of capital spending and including the effect of the Matador acquisition for the second half of 2003, Tom Brown s full year 2003 production guidance is approximately 97-100 Bcfe (85% natural gas). The mid-point estimate of the range for the third quarter 2003 production is approximately 26.9 Bcfe as summarized in the following table.

	Third Quarter 2003		
	U.S.	Canada	Total
Natural gas (Mcfpd)	230,000	17,000	247,000
Natural gas liquids (Bonglpd)	3,200	600	3,800
Oil (Bopd)	3,200	500	3,700
Total equivalent (Mcfepd)	268,400	23,600	292,000
Total production (Mmcfe)	24,700	2,200	26,900

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Estimates for exploration expense are $15-$20 million for the third quarter of 2003 and $41-$43 million for the entire year, including estimated dry hole expense. Actual dry hole expense could differ based on timing and results of wells. Other operating expenses for the remainder of 2003 are expected to fall within the ranges summarized below based on our estimated production:

OPERATING COSTS/Mcfe:					
Lease operating expense	$	0.43	-	$	0.45
General and administrative expense		0.22	-		0.24
Interest expense and other		0.34	-		0.38
Depreciation, depletion and amortization		1.13	-		1.16
Production taxes (% of oil and gas revenues)		8.5%	-		9.5%

The interest expense estimate assumes the entire purchase price for the Matador acquisition remains funded through the end of the year under our senior bank credit facility and senior subordinated credit facility and does not take into account any refinancing the Company is currently evaluating in the capital markets including the issuance of equity and debt securities.

The Company s management will hold a conference call tomorrow, Friday, August 8, 2003 at 1:00 p.m. Mountain Time to review the second quarter 2003 results. The dial-in number to participate in the call is 800-399-0117 (U.S.) or 706-679-3393 (International), or the call can be accessed live in a listen-only mode by following the link from the Investor Relations page of the Company s website www.tombrown.com.

Tom Brown, Inc. is a Denver, Colorado based independent energy company engaged in the exploration for, and the acquisition, development, production and marketing of, natural gas, natural gas liquids and crude oil in North America. The Company s common stock is traded on the NYSE under the symbol TBI.

This news release includes forward-looking statements within the meaning of section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These statements are based on certain assumptions and analyses made by the Company in light of its experience, on general economic and business conditions and expected future developments, many of which are beyond the control of the Company. Important factors that could cause actual results to differ materially from those in the forward-looking statements herein include the timing and extent of changes in commodity prices for oil and gas, environmental risks, operating risks, risks related to exploration and development, effective integration of acquired operations, the ability of the Company to meet its stated business goals and other risk factors as described in the Company s 2002 Annual Report and Form 10-K as filed with the Securities and Exchange Commission. As a result of those factors, the Company s actual results may differ materially from those indicated in or implied by such forward-looking statements.

Contact: Tom Brown, Inc.
Mark Burford
Director of Investor Relations
(303) 260-5146

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TOM BROWN, INC. AND SUBSIDIARIES

Consolidated Summary Income Statement (Unaudited)

Three and Six Months ended June 30, 2003 and 2002

	Three months ended June 30,				Six months ended June 30,			
	2003		2002		2003		2002	
	(In thousands except per share amounts)							
Revenues:								
Gas, oil and natural gas liquids sales	$	78,480	$	53,412	$	158,960	$	94,930
Gathering and processing		4,792		4,725		10,868		9,989
Marketing and trading		8,794		16,813		22,648		36,032
Drilling		3,878		2,750		6,955		4,581
Gain on sale of property				4,004				4,004
Change in fair value of derivatives		1,913		(1,653)		1,913		(1,653)
Loss on marketable securities				(600)				(600)
Interest income and other		76		63		627		326
Total revenues	$	97,933	$	79,514	$	201,971	$	147,609
Costs and expenses:								
Gas and oil production	$	8,505	$	8,148	$	16,690	$	16,319
Taxes on gas and oil production		7,085		4,892		13,623		8,800
Gathering and processing costs		2,037		1,703		4,071		3,224
Trading		8,449		15,539		21,590		35,340
Drilling operations		3,097		3,001		6,031		4,939
Exploration costs		3,805		7,601		10,679		11,184
Impairments of leasehold costs		1,489		1,393		2,963		2,781
General and administrative		5,803		4,493		10,650		9,365
Depreciation, depletion and amortization		23,153		23,496		44,570		46,023
Bad debts		100		108		252		216
Accretion expense		296				588		
Interest expense and other		2,262		2,536		5,818		3,905
Total costs and expenses	$	66,081	$	72,910	$	137,525	$	142,096
Income before income taxes and cumulative effect of change in accounting principle	$	31,852	$	6,604	$	64,446	$	5,513
Income tax benefit (provision)								
Current		777		(211)		555		(87)
Deferred		(11,273)		(1,638)		(22,848)		(1,042)
Income before cumulative effect of change in accounting principle		21,356		4,755		42,153		4,384
Cumulative effect of change in accounting principle						(929)		(18,103)

Net income (loss)	$	21,356	$	4,755	$	41,224	$	(13,719)
Weighted average number of common shares outstanding:								
Basic		39,473		39,188		39,478		39,168
Diluted		40,532		40,530		40,487		40,425
Income per common share before cumulative effect of change in accounting principle								
Basic	$	0.54	$	0.12	$	1.07	$	0.11
Diluted	$	0.53	$	0.12	$	1.04	$	0.11
Net income (loss) per common shareholder								
Basic	$	0.54	$	0.12	$	1.04	$	(0.35)
Diluted	$	0.53	$	0.12	$	1.02	$	(0.34)

TOM BROWN, INC. AND SUBSIDIARIES

Supplemental Financial Information

Three and Six Months ended June 30, 2003 and 2002

	Three months ended June 30,		Six months ended June 30,	
	2003	2002	2003	2002
		(in thousands)		
Reconciliation to net cash provided by operating activities:				
Discretionary cash flow (1)	$ 59,892	$ 36,820	$ 122,321	$ 63,351
Exploration costs	(3,805)	(7,601)	(10,679)	(11,184)
Add back only dry hole cost	1,231	2,769	4,268	2,842
Changes in current assets and liabilities, net	(8,744)	5,101	(30,422)	2,472
Net cash provided by operating activities	$ 48,574	$ 37,089	$ 85,488	$ 57,481

(1) Discretionary cash flow is presented herein because of its wide acceptance as a financial indicator of a company s ability to internally fund exploration and development activities and to service or incur debt. Discretionary cash flow should not be considered as an alternative to net cash provided by operating activities, net income (loss) or income (loss) from continuing operations, as defined by generally accepted accounting principles. Discretionary cash flow should also not be considered as an indicator of the Company s financial performance, as an alternative to cash flow, as a measure of liquidity or as being comparable to other similarly titled measures of other companies.

	June 30, 2003	December 31, 2002
Balance Sheet Data:		
Total assets	$ 1,475,055	$ 850,952
Net working capital	6,197	(8,887)
Total debt	543,652	133,172
Shareholders equity	606,472	563,618
Net debt/total book capital	47%	20%

TOM BROWN, INC. AND SUBSIDIARIES

Supplemental Operational Data (Unaudited)

Three and Six Months ended June 30, 2003 and 2002

	Three months ended June 30,		Six months ended June 30,	
	2003	2002	2003	2002
Production (net of royalties)				
Natural Gas (Bcf)				
United States	15.4	17.0	30.6	33.3
Canada	1.6	1.7	3.2	3.3
	17.0	18.7	33.8	36.6
Oil (MBbls)				
United States	153.3	170.2	279.8	352.0
Canada	55.3	50.3	109.1	103.4
	208.6	220.5	388.9	455.4
NGLs (MBbls)				
United States	318.2	329.7	648.6	633.3
Canada	50.0	48.4	98.2	91.9
	368.2	378.1	746.8	725.2
Average daily production (net of royalties)				
Natural Gas (Mmcf)				
United States	168.5	186.8	169.2	184.1
Canada	18.0	18.6	17.3	18.3
	186.5	205.4	186.5	202.4
Oil (Bbls)				
United States	1,684	1,870	1,546	1,945
Canada	608	554	603	571
	2,292	2,424	2,149	2,516
NGLs (Bbls)				
United States	3,497	3,623	3,583	3,499
Canada	549	531	543	508
	4,046	4,154	4,126	4,007
Average realized price (including effects of hedges):				
Natural Gas ($/Mcf)				
United States	$ 3.78	$ 2.30	$ 3.87	$ 2.06
Canada	5.05	2.95	4.90	2.79
Combined	3.90	2.36	3.97	2.13

Oil ($/Bbl)				
United States	$ 26.65	$ 22.86	$ 28.02	$ 21.23
Canada	28.49	26.54	30.80	22.20
Combined	27.14	23.70	28.80	21.45
NGLs ($/Bbl)				
United States	$ 16.99	$ 10.33	$ 17.20	$ 9.26
Canada	23.12	14.49	25.65	13.27
Combined	17.82	10.86	18.31	9.77