MERIDIAN RESOURCE CORP
Form 10-Q
August 14, 2003

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-Q

(Mark One)

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended: June 30, 2003

OR

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

For the transition period from __________________ to _________________

Commission file number: 1-10671

THE MERIDIAN RESOURCE CORPORATION
(Exact name of registrant as specified in its charter)

TEXAS	76-0319553
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1401 ENCLAVE PARKWAY, SUITE 300, HOUSTON, TEXAS	77077
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: 281-597-7000

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes [X] No [ ]

Number of shares of common stock outstanding at August 6, 2003   50,204,101

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THE MERIDIAN RESOURCE CORPORATION

QUARTERLY REPORT ON FORM 10-Q

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PART I - FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

THE MERIDIAN RESOURCE CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(thousands of dollars, except per share information)
(unaudited)

	THREE MONTHS ENDED JUNE 30,		
REVENUES:	2003	2002	2

Oil and natural gas	$ 29,603	$ 31,661	$
Price risk management activities	--	670	
Interest and other	51	142	
	29,654	32,473	
OPERATING COSTS AND EXPENSES:			
Oil and natural gas operating	2,803	3,013	
Severance and ad valorem taxes	1,548	2,400	
Depletion and depreciation	15,187	13,558	
Accretion expense	128	--	
General and administrative	2,972	2,984	
	22,638	21,955	
EARNINGS BEFORE INTEREST AND INCOME TAXES	7,016	10,518	
OTHER EXPENSES:			
Interest expense	3,611	3,744	
EARNINGS (LOSS) BEFORE INCOME TAXES	3,405	6,774	
INCOME TAXES			
Current	--	100	
Deferred	--	2,400	
	--	2,500	
NET EARNINGS (LOSS) BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	3,405	4,274	
Cumulative effect of change in accounting principle	--	--	
NET EARNINGS (LOSS)	3,405	4,274	
Dividends on preferred stock	1,481	1,102	
NET EARNINGS (LOSS) APPLICABLE TO COMMON STOCKHOLDERS	$ 1,924	$ 3,172	$
NET EARNINGS (LOSS) PER SHARE BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE			
Basic and Diluted	$ 0.04	$ 0.06	$
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING ACCOUNTING PRINCIPLE PER SHARE:			
Basic and Diluted	$ --	$ --	$
NET EARNINGS (LOSS) PER SHARE:			
Basic and Diluted	$ 0.04	$ 0.06	$
WEIGHTED AVERAGE NUMBER OF COMMON SHARES:			
Basic and Diluted	50,163	49,916	

See notes to consolidated financial statements.

THE MERIDIAN RESOURCE CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(thousands of dollars)

	JUNE 30, 2003 (unaudited)
ASSETS	
CURRENT ASSETS:	
Cash and cash equivalents	$ 10,132
Accounts receivable, less allowance for doubtful accounts $833 [2003 and 2002]	28,832
Due from affiliates	1,029
Prepaid expenses and other	3,464
Assets from price risk management activities	2,030
Total current assets	45,487
PROPERTY AND EQUIPMENT:	
Oil and natural gas properties, full cost method (including $22,581 [2003] and $18,993 [2002] not subject to depletion)	1,197,230
Land	478
Equipment	9,964
	1,207,672
Less accumulated depletion and depreciation	791,696
Total property and equipment, net	415,976
OTHER ASSETS:	
Assets from price risk management activities	145
Deferred tax asset	4,415
Other	5,568
Total other assets	10,128
Total assets	$ 471,591

See notes to consolidated financial statements.

THE MERIDIAN RESOURCE CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (continued)
(thousands of dollars)

	JUNE 30, 2003
	(unaudited)
LIABILITIES AND STOCKHOLDERS' EQUITY	
CURRENT LIABILITIES:	
Accounts payable	$ 14,613
Revenues and royalties payable	14,426
Notes payable	1,084
Accrued liabilities	11,370
Liabilities from price risk management activities	10,961
Current income taxes payable	931
Current portion long-term debt	34,000
Total current liabilities	87,385
LONG-TERM DEBT	148,500
9 1/2% CONVERTIBLE SUBORDINATED NOTES	20,000
OTHER:	
Liabilities from price risk management activities	3,827
Abandonment costs	4,779
	8,606
REDEEMABLE PREFERRED STOCK:	
Preferred stock, $1.00 par value (1,500,000 shares authorized, 726,500 [2003] and 696,900 [2002] shares of Series C Redeemable Convertible Preferred Stock issued at stated value)	72,650
STOCKHOLDERS' EQUITY:	
Common stock, $0.01 par value (200,000,000 shares authorized, 53,868,343 [2003 and 2002] issued)	564
Additional paid-in capital	378,262
Accumulated deficit	(206,093)
Accumulated other comprehensive loss	(8,383)
Unamortized deferred compensation	(311)
	164,039
Less treasury stock, at cost (3,684,741 shares [2003] and 3,779,225 [2002] shares)	29,589
Total stockholders' equity	134,450
Total liabilities and stockholders' equity	$ 471,591

See notes to consolidated financial statements.

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THE MERIDIAN RESOURCE CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(thousands of dollars)
(unaudited)

	SIX MONTH JUNE 2003
CASH FLOWS FROM OPERATING ACTIVITIES:	
Net earnings	$ 6,607
Adjustments to reconcile net earnings to net cash provided by operating activities:	
Cumulative effect of change in accounting principle	1,309
Depletion and depreciation	29,842
Amortization of other assets	1,137
Non-cash compensation	676
Non-cash price risk management activities	--
Accretion expense	256
Deferred income taxes	--
Changes in assets and liabilities:	
Accounts receivable	(4,665)
Due from affiliates	528
Prepaid expenses and other	(1,243)
Accounts payable	(2,229)
Revenues and royalties payable	2,048
Accrued liabilities and other	1,153
Net cash provided by (used in) operating activities	35,419
CASH FLOWS FROM INVESTING ACTIVITIES:	
Additions to property and equipment	(31,669)
Sale of property and equipment	39
Net cash used in investing activities	(31,630)
CASH FLOWS FROM FINANCING ACTIVITIES:	
Redeemable preferred stock	--
Reductions in long-term debt	(1,250)
Proceeds from notes payable	1,439
Reductions in notes payable	(1,187)
Issuance of stock/exercise of options	180
Preferred dividends	--
Additions to deferred loan costs	(126)
Net cash provided by (used in) financing activities	(944)
NET CHANGE IN CASH AND CASH EQUIVALENTS	2,845
Cash and cash equivalents at beginning of period	7,287
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 10,132

See notes to consolidated financial statements.

THE MERIDIAN RESOURCE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

1. BASIS OF PRESENTATION

The consolidated financial statements reflect the accounts of The Meridian Resource Corporation and its subsidiaries (the "Company") after elimination of all significant intercompany transactions and balances. The financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 2002, as filed with the Securities and Exchange Commission.

The financial statements included herein as of June 30, 2003, and for the three and six month periods ended June 30, 2003 and 2002, are unaudited, and in the opinion of management, the information furnished reflects all material adjustments, consisting of normal recurring adjustments, necessary for a fair statement of the results for the interim periods presented. Certain minor reclassifications of prior period statements have been made to conform to current reporting practices.

2. DEBT

CREDIT FACILITY. During August 2002, the Company replaced its Chase Manhattan Bank Credit Facility with a new three-year $175 million underwritten senior secured credit agreement (the "Credit Agreement") with Societe Generale, as administrative agent, lead arranger and book runner, and Fortis Capital Corp., as co-lead arranger and documentation agent. Borrowings under the Credit Agreement mature on August 13, 2005. The initial borrowing base under the existing Credit Agreement was established on September 23, 2002, at $165 million, with the first borrowing base redetermination date scheduled for November 30, 2002. The parties to the Credit Agreement entered into an amendment of the Agreement, effective March 31, 2003, to eliminate the November 30, 2002, redetermination date and to reschedule the borrowing base redetermination date for April 30, 2003, with quarterly redetermination thereafter.

On March 31, 2003, the Company received notice from its senior lenders that effective April 30, 2003, the borrowing base was established at $138.5 million. Accordingly, the Company has reflected the difference of $26.5 million as a current maturity of its long-term debt and was required to make up the deficiency through the addition of reserves or value to its current reserve base or pay the senior lenders the noticed deficiency within 90 days of the effective date of April 30, 2003. On July 29, 2003, the lenders consented to an extension until September 12, 2003. Though no assurances can be made that sufficient funds will be available to pay this deficiency, management believes that it can satisfy this deficiency through a combination of the addition of reserves, third-party financing, property sales and cash flow.

In addition to the scheduled quarterly borrowing base redeterminations, the lenders or borrower, under the Credit Agreement, have the right to redetermine the borrowing base at any time once during each calendar year. Borrowings under the Credit Agreement are secured by pledges of outstanding capital stock of the Company's subsidiaries and a mortgage on the Company's oil and natural gas properties of at least 90% of its present value of proved properties. The Credit Agreement contains various restrictive covenants, including, among other items, maintenance of certain financial ratios and restrictions on cash dividends on Common Stock and under certain circumstances Preferred Stock and an unqualified audit report on the Company's consolidated financial statements beginning with those as of and for the year ended December 31, 2002. The Company has received from the senior lenders a waiver of the covenant that would have triggered an event of default as a result of the independent auditors' report which contained a "going concern" modification for our 2002 consolidated financial statements.

Under the Credit Agreement, the Company may secure either (i) an alternative base rate loan that bears interest at a rate per annum equal to the greater of the administrative agent's prime rate plus an additional 0.5% to 1.5% depending on the ratio of the aggregate outstanding loans and letters of credit to the borrowing base; or a federal funds-based rate plus 1/2 of 1% or (ii) a Eurodollar base rate loan that bears interest, generally, at a rate per annum equal to the London interbank offered rate ("LIBOR") plus 1.5% to 2.5%, depending on the ratio of the aggregate outstanding loans and letters of credit to the borrowing base. The Credit Agreement also provides for commitment fees ranging from 0.375% to 0.5% per annum.

SUBORDINATED CREDIT AGREEMENT. The Company extended and amended a short-term subordinated credit agreement with Fortis Capital Corporation for $25 million on April 5, 2002, with a maturity date of December 31, 2004. The notes are unsecured and contain customary events of default, but do not contain any maintenance or other restrictive covenants. The interest rate is LIBOR plus 4.5% through December 31, 2002, LIBOR plus 5.5% from January 1, 2003, through August 31, 2003, and LIBOR plus 6.5% from September 1, 2003, through December 31, 2004. Note payments of $5 million each are due on August 31, 2003 and April 30, 2004, with the remaining $5 million payable on December 31, 2004. Note payments totaling $1.25 million were paid in January 2003, bringing the outstanding balance to $17.5 million. An additional $2.5 million that is currently due has been deferred in conjunction with the March 31, 2003, amendment to the Credit Agreement. No amounts are payable under this subordinated debt until any and all borrowing base deficiencies under the Credit Agreement are satisfied. The Company is in compliance with the terms of this agreement.

3. EARNINGS PER SHARE (in thousands, except per share)

The following tables set forth the computation of basic and diluted net earnings per share:

	THREE MONTHS END 2003
Numerator:	
Net earnings applicable to common stockholders	$ 1,924
Plus income impact of assumed conversions:	
Preferred stock dividends	1,481
Interest on convertible subordinated notes	309
Net earnings applicable to common stockholders plus assumed conversions	$ 3,714
Denominator:	
Denominator for basic net earnings per	

share - weighted-average shares outstanding	50,163
Effect of potentially dilutive common shares:	
Redeemable preferred stock	N/A
Convertible subordinated notes	N/A
Employee and director stock options	N/A
Warrants	N/A
Denominator for diluted net earnings per share - weighted-average shares outstanding and assumed conversions	50,163
Basic net earnings per share	$ 0.04
Diluted net earnings per share	$ 0.04

	SIX MONTHS ENDED
	2003
Numerator:	
Net earnings applicable to common stockholders	$ 3,645
Plus income impact of assumed conversions:	
Preferred stock dividends	2,962
Interest on convertible subordinated notes	618
Net earnings applicable to common stockholders plus assumed conversions	$ 7,225
Denominator:	
Denominator for basic net earnings per share - weighted-average shares outstanding	50,126
Effect of potentially dilutive common shares:	
Redeemable preferred stock	N/A
Convertible subordinated notes	N/A
Employee and director stock options	N/A
Warrants	N/A
Denominator for diluted net earnings per share - weighted-average shares outstanding and assumed conversions	50,126
Basic net earnings per share	$ 0.07
Diluted net earnings per share	$ 0.07

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4. OIL AND NATURAL GAS HEDGING ACTIVITIES

The Company may address market risk by selecting instruments whose value fluctuations correlate strongly with the underlying commodity being hedged. The

Company enters into swaps and other derivative contracts to hedge the price risks associated with a portion of anticipated future oil and gas production. These swaps allow the Company to predict with greater certainty the effective oil and natural gas prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended. While the use of hedging arrangements limits the downside risk of adverse price movements, it may also limit future gains from favorable movements. Under these agreements, payments are received or made based on the differential between a fixed and a variable product price. These agreements are settled in cash at or prior to expiration or exchanged for physical delivery contracts. The Company does not obtain collateral to support the agreements, but monitors the financial viability of counter-parties and believes its credit risk is minimal on these transactions. In the event of nonperformance, the Company would be exposed to price risk. The Company has some risk of accounting loss since the price received for the product at the actual physical delivery point may differ from the prevailing price at the delivery point required for settlement of the hedging transaction.

These swaps have been designated as cash flow hedges as provided by Statement of Financial Accounting Standards (SFAS) No. 133 and any changes in fair value of the cash flow hedge resulting from ineffectiveness of the hedge is reported in the consolidated statement of operation as revenues.

The estimated June 30, 2003, fair value of the Company's oil and natural gas swaps is an unrealized loss of $12.6 million ($8.2 million net of tax) recognized in other comprehensive income. Based upon June 30, 2003, oil and natural gas commodity prices, approximately $8.9 million of the loss deferred in other comprehensive income is expected to lower gross revenues over the next twelve months when the revenues are generated. The swap agreements expire at various dates through July 31, 2005.

Payments under these swap agreements reduced oil and natural gas revenues by $3,026,000 for the three months and $10,131,000 for the six months ended June 30, 2003, as a result of hedging transactions.

The notional amount is equal to the total net volumetric hedge position of the Company during the periods presented. The positions effectively hedge approximately 19% of our proved developed natural gas production and 74% of our proved developed oil production. The fair values of the hedges are based on the difference between the strike price and the New York Mercantile Exchange future prices for the applicable trading months.

	Notional Amount	Weighted Average Strike Price ($ per unit)	Fair a
Natural Gas (mmbtu)			
July 2003 - June 2005	5,820,000	$ 3.77	$
Oil (bbls)			
July 2003 - July 2005	1,451,000	$ 24.04	$
			$

5. STOCK-BASED COMPENSATION

SFAS 123, "Accounting for Stock-Based Compensation," as amended by SFAS 148, "Accounting for Stock-Based Compensation - Transition and Disclosure," established accounting and disclosure requirements using a fair value-based method of accounting for stock-based employee compensation plans. As provided for under SFAS 123, there has been no amount of compensation expense recognized for the Company's stock option plans. The Company accounts for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board Opinion 25, "Accounting for Stock Issued to Employees." Compensation expense is recorded for restricted stock awards over the requisite vesting periods based upon the market value on the date of the grant. The compensation expense incurred in the three month and six month periods ended June 30, 2003 and 2002, related to restricted stock awards totaled $10 thousand for each quarter, respectively.

The following is a reconciliation of reported earnings (loss) and earnings (loss) per share as if the Company used the fair value method of accounting for stock-based compensation. Fair value is calculated using the Black-Scholes option pricing model. (In thousands, except per share data.)

	Three Months End	
	2003	
Net earnings (loss) applicable to common stockholders as reported ($000)	$	1,924
Stock-based compensation expense determined under fair value method for all awards, net of tax ($000)		10
Net earnings (loss) applicable to common stockholders pro forma ($000)	$	1,914
Basic earnings (loss) per share:		
As reported	$	0.04
Pro forma	$	0.04
Diluted earnings (loss) per share:		
As reported	$	0.04
Pro forma	$	0.04

	Six Months E	
	2003	
Net earnings (loss) applicable to common stockholders as reported ($000)	$	3,645
Stock-based compensation expense determined under fair value method for all awards, net of tax ($000)		20
Net earnings (loss) applicable to common stockholders pro forma ($000)	$	3,625
Basic earnings (loss) per share:		

As reported	$	0.07
Pro forma	$	0.07
Diluted earnings (loss) per share:		
As reported	$	0.07
Pro forma	$	0.07

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6. ASSET RETIREMENT OBLIGATIONS

On January 1, 2003, the Company adopted SFAS 143, "Accounting for Asset Retirement Obligations." This statement requires entities to record the fair value of a liability for legal obligations associated with the retirement obligations of tangible long-lived assets in the period in which it is incurred. The fair value of asset retirement obligation liabilities has been calculated using an expected present value technique. Fair value, to the extent possible, should include a market risk premium for unforeseeable circumstances. No market risk premium was included in the Company's asset retirement obligations fair value estimate since a reasonable estimate could not be made. When the liability is initially recorded, the entity increases the carrying amount of the related long-lived asset. Over time, accretion of the liability is recognized each period, and the capitalized cost is amortized over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. This standard requires us to record a liability for the fair value of our dismantlement and abandonment costs, excluding salvage values.

Upon adoption, the Company recorded transition amounts for liabilities related to our wells, and the associated costs to be capitalized. A liability of $4.5 million was recorded to long-term liabilities and a net asset of $3.2 million was recorded to oil and natural gas properties on January 1, 2003. This resulted in a cumulative effect of an accounting change of ($1.3) million. Accretion expenses subsequent to the adoption of this accounting statement decreased net earnings $256 thousand in the first six months of 2003.

The pro forma effects of the application of SFAS 143 as if the statement had been adopted on January 1, 2002, is presented below (thousands of dollars except per share information):

	Three Months Ended June 30,				Six Months
	2003		2002		2003
Net earnings (loss) as reported	$ 3,405	$	4,274	$	6,607
Additional accretion expense	--		(117)		--
Cumulative effect of accounting change	--		--		1,309
Pro forma net earnings (loss)	$ 3,405	$	4,157	$	7,916
Pro forma net earnings (loss) per share	$ 0.04	$	0.06	$	0.10

The following table describes the change in the Company's asset retirement obligations for the period ended June 30, 2003, and the pro forma amounts for 2002 (thousands of dollars):

Asset retirement obligation at January 1, 2002	$	4,053
Accretion expense		470
Asset retirement obligation at December 31, 2002		4,523
Accretion expense		256
Asset retirement obligation at June 30, 2003	$	4,779

7. NEW ACCOUNTING PRONOUNCEMENT

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51". Interpretation No. 46 requires a company to consolidate a variable interest entity ("VIE") if the company has variable interest that is exposed to a majority of the entity's expected losses if they occur, receive a majority of the entity's expected residual returns if they occur, or both. In addition, more extensive disclosure requirements apply to the primary and other significant variable owners of the VIE. This interpretation applies immediately to VIEs created after January 31, 2003, and to VIEs in which an enterprise obtains an interest after that date. It is also effective for the first fiscal year

or interim period beginning after June 15, 2003, to VIEs in which a company holds a variable interest that is acquired before February 1, 2003. The guidance regarding this interpretation is extremely complex and, although we do not believe we have an interest in a VIE, the Company continues to assess the impact, if any, this interpretation will have on the Company's consolidated financial statements.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following is a discussion of Meridian's financial operations for the three months and six months ended June 30, 2003 and 2002. The notes to the Company's consolidated financial statements included in this report, as well as our Annual Report on Form 10-K for the year ended December 31, 2002 (and the notes attached thereto), should be read in conjunction with this discussion.

GENERAL

BUSINESS ACTIVITIES. During the first six months of 2003, Meridian's exploration activities have been focused primarily in the Company's Biloxi Marshlands acreage. We anticipate drilling and 3-D seismic activities in the Biloxi Marshlands acreage will comprise the majority of our capital budget for 2003.

During the second quarter of 2003, capital expenditures were focused primarily in our Biloxi Marshland play. The Company continued to increase its near term daily production rates by completing and placing on production two additional wells, the Biloxi Marshlands No. 6-2 and No. 7-1 wells. In early August, the Biloxi Marshlands No. 1-2 well was placed on production. With the addition of these three new wells, the Biloxi Marshlands project area has produced at rates as high as approximately 74 MMCF/D (44 MMCF/D net). However, this rate is dependent on the transporting pipeline's operating pressure, which is subject to fluctuations. Drilling operations are currently being conducted on the Company's Biloxi Marshlands No. 18-1 well which is drilling at approximately 9,300 feet.

Other activities during the second quarter of 2003 included the acquisition of 187 square miles of 3-D seismic data adjacent to and south and east of the recent well activity announced by the Company. It is anticipated that this new 3-D seismic data will form the basis of new project in this area.

Although the Company has identified as many as 5-7 prospective drilling opportunities in its Biloxi Marshland project area, future wells in this area during 2003 beyond the Biloxi Marshlands No. 18-1 well will depend on budget availability, permitting, leasing and access issues as well as the results and timing of completing the acquisition, processing and interpretation of the new 3-D seismic data currently being acquired.

In addition to the activities in the Biloxi Marshlands project area, the Company has recently logged Ship Shoal prospect which was spudded in early July 2003. Meridian owns a 43% working interest. The well tested the Lower Pleistocene sands at approximately 13,000 feet but was found to be noncommercial and is presently being plugged and abandoned by the operator. Net cost to Meridian was approximately $2 million.

Two significant workover and recompletions have been completed during 2003. The Avoca No. 47-1 well was placed back on production during May at a rate of 8 MMCFE/D. In addition, the Thibodaux No. 1 well was returned to production during July at a rate of 19 MMCFE/D. Collectively a net addition to Meridian of approximately 14 MMCFE/D, replacing production that was offstream during most of the second quarter of 2003.

INDUSTRY CONDITIONS. Revenues, profitability and future growth rates of Meridian are substantially dependent upon prevailing prices for oil and natural gas. Oil and natural gas prices have been extremely volatile in recent years and are affected by many factors outside of our control. Our average oil price (after adjustments for hedging activities) for the three months ended June 30, 2003, was $25.19 per barrel compared to $24.99 per barrel for the three months ended June 30, 2002, and $25.15 per barrel for the three months ended March 31, 2003. Our average oil price for the six months ended June 30, 2003, was $25.17 per barrel compared to $22.80 per barrel for the six months ended June 30, 2002. Our average natural gas price (after adjustments for hedging activities) for the three months ended June 30, 2003, was $5.39 per Mcf compared to $3.69 per Mcf for the three months ended June 30, 2002, and $5.82 per Mcf for the three months ended March 31, 2003. Our average natural gas price for the six months ended June 30, 2003, was $5.59 per Mcf compared to $3.08 per Mcf for the six months ended June 30, 2002. Fluctuations in prevailing prices for oil and natural gas have several important consequences to us, including affecting the level of cash flow received from our producing properties, the timing of exploration of certain prospects and our access to capital markets, which could impact our revenues, profitability and ability to maintain or increase our exploration and development program.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES. The Company's discussion and analysis of its financial condition and results of operation are based upon consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted and adopted in the United States. The preparation of these financial statements requires the Company to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. See the Company's Annual Report on Form 10-K for the year ended December 31, 2002, for further discussion.

RESULTS OF OPERATIONS

THREE MONTHS ENDED JUNE 30, 2003 COMPARED TO THREE MONTHS ENDED JUNE 30, 2002

OPERATING REVENUES. Second quarter 2003 oil and natural gas revenues decreased $2.1 million as compared to second quarter 2002 revenues, due to a 26% decrease in production volumes caused primarily from wells either being off production temporarily or impacted by mechanical issues. This was partially offset by a 27% increase in average commodity prices on a natural gas equivalent basis. The decrease in production was primarily a result of the Avoca 47-1 and Thibodaux No. 1 wells being out of production during the quarter, two Weeks Island wells encountering extraneous water production, which the Company is addressing with offset wells and natural production declines, primarily in the Thornwell, Gibson Humphries and Turtle Bayou fields. These reductions in production were partially offset by new production from the Biloxi Marshlands project area. Additional recoveries of production are expected from operations such as those conducted on the Avoca 47-1 and the Thibodaux No. 1 wells. It is expected that similar recoveries will occur as we conduct the operations in the Weeks Island field within the next 6-10 months. However, as always, there can be no assurances that other operations will be successful.

The following table summarizes the Company's operating revenues, production volumes and average sales prices for the three months ended June 30, 2003 and 2002:

	THREE MONTHS ENDED JUNE 30, 2003	2002	INCREASE (DECREASE)
Production Volumes:			
Oil (Mbbl)	347	631	(45%)
Natural gas (MMcf)	3,869	4,304	(10%)
Mmcfe	5,951	8,089	(26%)
Average Sales Prices:			
Oil (per Bbl)	$ 25.19	$ 24.99	1%
Natural gas (per Mcf)	$ 5.39	$ 3.69	46%
Mmcfe	$ 4.97	$ 3.91	27%
Operating Revenues (000's):			
Oil	$ 8,742	$15,768	(45%)
Natural gas	20,861	15,893	31%
Total Operating Revenues	$29,603	$31,661	(7%)

OPERATING EXPENSES. Oil and natural gas operating expenses decreased $0.2 million (7%) to $2.8 million for the three months ended June 30, 2003, compared to $3.0 million for the same period in 2002. This decrease primarily resulted from reorganization of field operations enabling the Company to reduce labor and other field related costs. This area of cost controls is a continuing focus of the Company.

SEVERANCE AND AD VALOREM TAXES. Severance and ad valorem taxes decreased $0.9 million (36%) to $1.5 million for the second quarter of 2003, compared to $2.4

million during the same period in 2002. Meridian's oil and natural gas production is primarily from Louisiana, and is therefore subject to Louisiana severance tax. The severance tax rates for Louisiana are 12.5% of gross oil revenues and $0.122 per Mcf for natural gas, a decrease from $0.199 per Mcf effective in July 2002. Our decrease was primarily due to the decrease in oil and natural gas production and the decrease in the natural gas tax rate, partially offset by the increase in oil prices.

DEPLETION AND DEPRECIATION. Depletion and depreciation expense increased $1.6 million (12%) during the second quarter of 2003 to $15.2 million from $13.6 million for the same period of 2002. This was primarily a result of an increased depletion rate for 2003 over 2002, partially offset by the decrease in production volumes in 2003 from 2002 levels.

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GENERAL AND ADMINISTRATIVE EXPENSE. General and administrative expense was reported as $3.0 million for the three month periods ended June 30, 2003 and 2002, respectively. As previously announced, during the first quarter of 2003, the Company initiated reductions in staff to reflect its change in exploration strategy to lower risk, higher probability projects maintaining its focus in its niche region of south Louisiana and southeast Texas. Although the full impact of these reductions has not been recognized because of the severance packages that continued through this and future quarters it is anticipated that these changes will result in future savings in costs without sacrificing the Company's exploration efforts or opportunities. To date, it is anticipated that the changes have reduced salaries by approximately 25%.

INTEREST EXPENSE. Interest expense decreased $0.1 million (4%) to $3.6 million for the second quarter of 2003 in comparison to the second quarter of 2002. The decrease is primarily a result of the reduction in the balance outstanding for the revolving credit lines and a decrease in the interest rates from the prior year, partially offset by a recent lead bank calculation adjustment of $0.9 million to the rate used for the credit facility.

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SIX MONTHS ENDED JUNE 30, 2003, COMPARED TO SIX MONTHS ENDED JUNE 30, 2002

OPERATING REVENUES. Oil and natural gas revenues during the six months ended June 30, 2003, increased $2.3 million as compared to revenues during the six months ended June 30, 2002, due to average sales prices increasing 48% partially offset by a decrease in production volumes of 30%, both on a natural gas equivalent basis. The production decrease is primarily a result of the Avoca 47-1 and Thibodaux No. 1 wells being out of production during a portion of the 2003 period and of natural production declines, partially offset by new wells brought on during 2003, the full impact of which will not be fully realized until mid-third quarter 2003.

The following table summarizes production volumes, average sales prices and gross revenues for the six months ended June 30, 2003 and 2002.

	SIX MONTHS ENDED JUNE 30, 2003	SIX MONTHS ENDED JUNE 30, 2002	INCREASE (DECREASE)

Production Volumes:			
Oil (Mbbl)	744	1,264	(41%)
Natural gas (MMcf)	7,132	8,900	(20%)
Mmcfe	11,597	16,484	(30%)
Average Sales Prices:			
Oil (Bbl)	$ 25.17	$ 22.80	10%
Natural gas (Mcf)	$ 5.59	$ 3.08	81%
MMcfe	$ 5.05	$ 3.41	48%
Gross Revenues (000's):			
Oil	$ 18,727	$ 28,822	(35%)
Natural gas	39,863	27,448	45%
Total	$ 58,590	$ 56,270	4%

OPERATING EXPENSES. Oil and natural gas operating expenses decreased $0.8 million (13%) to $5.3 million for the six months ended June 30, 2003, compared to $6.1 million for the six months ended June 30, 2002. This decrease was primarily due to a reorganization involving a reduction in labor costs and increased emphasis in operating cost reductions. This area of cost controls is a continuing focus of the Company.

SEVERANCE AND AD VALOREM TAXES. Severance and ad valorem taxes decreased $1.7 million (34%) to $3.4 million for the six months ended June 30, 2003, compared to $5.1 million for the six months ended June 30, 2002. This decrease is largely attributable to the decrease in production, the decrease in oil revenues from the same period in 2002 and a decrease in the tax rate for natural gas. Meridian's production is primarily from southern Louisiana, and, therefore, is subject to a current tax rate of 12.5% of gross oil revenues and $0.122 per Mcf for natural gas. The tax rate for natural gas for the first half of 2002 was $0.199 per Mcf.

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DEPLETION AND DEPRECIATION. Depletion and depreciation expense increased $2.9 million (11%) to $29.8 million during the first six months of 2003 from $26.9 million for the same period last year. This increase was primarily a result of increased depletion rate from 2002 levels, partially offset by the 30% decrease in production on an Mcfe basis from the comparable period in 2002.

GENERAL AND ADMINISTRATIVE EXPENSE. General and administrative expense decreased $0.4 million (7%) to $5.8 million for the first six months of 2003 compared to $6.2 million during the first six months of 2002. This reduction is partially due to a reduction in professional and technical services during 2003 as compared to 2002 levels. As previously announced, during the first quarter of 2003 the Company initiated reductions in staff to reflect its change in exploration strategy to lower risk, higher probability projects maintaining its focus in its niche region of south Louisiana and southeast Texas. Although the full impact of these reductions has not been recognized due to the severance packages included, it is anticipated that these changes will result in future savings in costs without sacrificing the Company's exploration efforts or opportunities.

INTEREST EXPENSE. Interest expense decreased $1.4 million (19%) to $6.2 million during the first six months of 2003 compared to $7.6 million during the comparable period of 2002. The decrease is primarily a result of the reduction in debt and the Federal Reserve Bank's decrease in overall interest rates which has led to a decrease in the average interest rate on the credit facility.

LIQUIDITY AND CAPITAL RESOURCES

WORKING CAPITAL. During the second quarter of 2003, Meridian's capital expenditures were internally financed with cash from operations. As of June 30, 2003, we had a cash balance of $10.1 million and a working capital deficit of $41.9 million. This deficit was made up primarily of $34 million of current maturities of long-term debt, and a $8.9 million net current liability associated with price risk management activities. Our strategy is to grow the Company prudently, taking advantage of the strong asset base built over the years to add reserves through the drill bit while maintaining a disciplined approach to costs. Where appropriate, we will allocate excess cash above capital expenditures to reduce leverage.

CREDIT FACILITY. During August 2002, the Company replaced its Chase Manhattan Bank Credit Facility with a new three-year $175 million underwritten senior secured credit agreement (the "Credit Agreement") with Societe Generale, as administrative agent, lead arranger and book runner, and Fortis Capital Corp., as co-lead arranger and documentation agent. The current borrowing base under the existing Credit Agreement was established on September 23, 2002, at $165 million, with the borrowing base redetermination date scheduled for November 30, 2002. The parties to the Credit Agreement have entered into an amendment of the Agreement, effective March 31, 2003, to eliminate the November 30, 2002, redetermination date and to reschedule the borrowing base redetermination date for April 30, 2003, and quarterly redetermination thereafter.

On March 31, 2003, the Company received notice from its senior lenders that effective April 30, 2003, the borrowing base was established at $138.5 million. Accordingly, the Company has reflected the difference of $26.5 million as a current maturity of its long-term debt and was required to make up the deficiency through the addition of reserves or value to its current reserve base or pay the senior lenders this deficiency within 90 days of the effective date of April 30, 2003. On July 29, 2003, the lenders consented to a 45 day extension of the deadline until September 12, 2003, enabling additional time for all parties to consider the various means by which the Company may achieve compliance and remove the borrowing base deficiency. As a result of the recent discoveries, additions to reserves and production, and anticipated additional cash flows, it is management's intent to use excess cash flow to reduce the total debt position without compromising its capital expenditures currently scheduled for its growth. Though no assurances can be made that sufficient funds will be available to pay this deficiency, management believes that it can satisfy this deficiency through a combination of the addition of reserves, third-party financing, property sales and cash flow.

In addition to the scheduled quarterly borrowing base redeterminations, the lenders under the Credit Agreement have the right to redetermine the borrowing base at any time once during each calendar year and the Company has the right to obtain a redetermination by the banks of the borrowing base once during each calendar year. Borrowings under the Credit Agreement are secured by pledges of outstanding capital stock of the Company's subsidiaries and a mortgage on the Company's oil and natural gas properties of at least 90% of its present value of proved properties. The Credit Agreement contains various restrictive covenants, including, among other items, maintenance of certain financial ratios and restrictions on cash dividends on Common Stock and an unqualified audit report on the Company's consolidated financial statements beginning with those as of and for the year ended December 31, 2002. Other than the borrowing base as calculated solely by the lender, the Company is in compliance with all financial ratios and loan covenants. The Company has received from the senior lenders a waiver of the covenant that would have triggered an event of default as a result of the independent auditors' report which contained a "going concern" modification for our 2002 consolidated financial statements. Borrowings under the Credit Agreement mature on August 13, 2005.

Under the Credit Agreement, the Company may secure either (i) an alternative base rate loan that bears interest at a rate per annum equal to the greater of the administrative agent's prime rate plus an additional 0.5% to 1.5% depending on the ratio of the aggregate outstanding loans and letters of credit to the borrowing base; or a federal funds-based rate plus 1/2 of 1% or (ii) a Eurodollar base rate loan that bears interest, generally, at a rate per annum equal to the London interbank offered rate ("LIBOR") plus 1.5% to 2.5%, depending on the ratio of the aggregate outstanding loans and letters of credit to the borrowing base. The Credit Agreement also provides for commitment fees ranging from 0.375% to 0.5% per annum.

SUBORDINATED CREDIT AGREEMENT. The Company extended and amended a short-term subordinated credit agreement with Fortis Capital Corporation for $25 million on April 5, 2002, with a maturity date of December 31, 2004. The notes are unsecured and contain customary events of default, but do not contain any maintenance or other restrictive covenants. The interest rate is LIBOR plus 4.5% through December 31, 2002, LIBOR plus 5.5% from January 1, 2003, through August 31, 2003, and LIBOR plus 6.5% from September 1, 2003, through December 31, 2004. Note payments of $5 million each are due on August 31, 2003 and April 30, 2004, with the remaining $5 million payable on December 31, 2004. Note payments totaling $1.25 million were paid in January 2003. An additional $2.5 million that is currently due has been deferred in conjunction with the March 31, 2003, amendment to the Credit Agreement. No amounts are payable under this subordinated debt until any and all borrowing base deficiencies under the Credit Agreement are satisfied. The Company is in compliance under this agreement.

CAPITAL RESOURCES AND LIQUIDITY As noted in our discussion of the Credit Facility, the agent bank, Societe Generale, noticed to the Company that it believes there is a $26.5 million borrowing base deficiency at April 30, 2003 that was to be satisfied by either sufficient additions to our proved reserves or repayment on or before July 29, 2003, to avoid an event of default. An event of default which is not cured results in the entire debt outstanding becoming due and payable, unless it is waived by the senior lenders or the Credit Agreement is otherwise amended. Also, repayment of $2.5 million, after our $1.25 million January 2003 payment, under our subordinated debt agreement is due but is deferred pending satisfaction of the borrowing base deficiency under the amended Credit Agreement. The $5 million subordinated debt repayment that will become due in August 2003 may also be subject to deferral for any borrowing base deficiencies that may exist at that time. The total amounts noticed as due or $34 million due under these agreements represents a significant component of our $41.9 million working capital deficiency at June 30, 2003.

In conjunction with the amendment to the Credit Agreement of March 31, 2003, the lenders permitted the Company to continue its capital expenditure program as scheduled. As a result, although significant new reserves have been recently added to the Company's reserves, the Company has paid only $2.5 million toward the reduction of its credit facility. To this end we have obtained a 45 day extension from our bank group to allow for a sufficient amount of time to negotiate a modification to our credit facility. Although we can make no assurances that we can successfully reach an agreement, we anticipate that the modification will take the form of an amortization schedule over a specified time period. We do not expect these monthly payments to impede our anticipated $30 to $35 million of capital expenditures for the remainder of the year.

Further, the Company continues to discuss with third parties the infusion of capital in the form of subordinated debt, equity or a combination of both. Although we can make no assurances as to when or in what amounts, if any, that third parties may agree to make any such investments on terms reasonably satisfactory to us, if we obtain such capital, the proceeds would be used primarily to reduce the current indebtedness of the senior credit facility as well as to fund capital expenditures for calendar year 2003.

Although there can be no assurances, additions to reserves, sufficient proceeds from the sale of non-strategic oil and natural gas properties and new subordinated debt or similar financing arrangements may be generated in sufficient time to satisfy our funding obligations under both the Credit Agreement and the subordinated debt agreement to permit an orderly reduction and restructuring of our debt capital.

OIL AND NATURAL GAS HEDGING ACTIVITIES. The Company may address market risk by selecting instruments whose value fluctuations correlate strongly with the underlying commodity being hedged. The Company enters into swaps and other derivative contracts to hedge the price risks associated with a portion of anticipated future oil and gas production. These swaps allow the Company to predict with greater certainty the effective oil and natural gas prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended. While the use of hedging arrangements limits the downside risk of adverse price movements, it may also limit future gains from favorable movements. Under these agreements, payments are received or made based on the differential between a fixed and a variable product price. These agreements are settled in cash at or prior to expiration or exchanged for physical delivery contracts. The Company does not obtain collateral to support the agreements, but monitors the financial viability of counter-parties and believes its credit risk is minimal on these transactions. In the event of nonperformance, the Company would be exposed to price risk. The Company has some risk of accounting loss since the price received for the product at the actual physical delivery point may differ from the prevailing price at the delivery point required for settlement of the hedging transaction.

These swaps have been designated as cash flow hedges as provided by SFAS 133 and any changes in fair value of the cash flow hedge resulting from ineffectiveness of the hedge is reported in the consolidated statement of operations as revenues.

CAPITAL EXPENDITURES. In the second quarter of 2003, Meridian's exploration activities have been focused primarily in the Company's Biloxi Marshlands acreage. As a result of the low-risk nature of this play and its confirmation with the recent drilling successes, we anticipate the drilling and 3-D seismic activities in the Biloxi Marshlands area will comprise the majority of our 2003 capital budget. We expect to spend approximately $30 to $35 million in capital expenditures during the last six months of the year.

DIVIDENDS. It is our policy to retain existing cash for reinvestment in our business, and therefore, we do not anticipate that dividends will be paid with respect to the Common Stock in the foreseeable future. During May 2002, the

Company completed the private placement of $67 million of 8.5% redeemable convertible preferred stock and dividends are payable semi-annually. Under the terms of the Credit Agreement, dividend payments required during 2003 on the preferred stock have been paid-in-kind through our issuance of additional preferred stock.

FORWARD-LOOKING INFORMATION

From time to time, we may make certain statements that contain "forward-looking" information as defined in the Private Securities Litigation Reform Act of 1995 and that involve risk and uncertainty. These forward-looking statements may include, but are not limited to exploration and seismic acquisition plans, anticipated results from current and future exploration prospects, future capital expenditure plans and plans to sell properties, anticipated results from third party disputes and litigation, expectations regarding future financing and compliance with our credit facility, the anticipated results of wells based on logging data and production tests, future sales of production, earnings, margins, production levels and costs, market trends in the oil and natural gas industry and the exploration and development sector thereof, environmental and other expenditures and various business trends. Forward-looking statements may be made by management orally or in writing including, but not limited to, the Management's Discussion and Analysis of Financial Condition and Results of Operations section and other sections of our filings with the Securities and Exchange Commission under the Securities Act of 1933, as amended, and the Securities Exchange Act of 1934, as amended.

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Actual results and trends in the future may differ materially depending on a variety of factors including, but not limited to the following:

Changes in the price of oil and natural gas. The prices we receive for our oil and natural gas production and the level of such production are subject to wide fluctuations and depend on numerous factors that we do not control, including seasonality, worldwide economic conditions, the condition of the United States economy (particularly the manufacturing sector), foreign imports, political conditions in other oil-producing countries, the actions of the Organization of Petroleum Exporting Countries and domestic government regulation, legislation and policies. Material declines in the prices received for oil and natural gas could make the actual results differ from those reflected in our forward-looking statements.

Operating Risks. The occurrence of a significant event against which we are not fully insured could have a material adverse effect on our financial position and results of operations. Our operations are subject to all of the risks normally incident to the exploration for and the production of oil and natural gas, including uncontrollable flows of oil, natural gas, brine or well fluids into the environment (including groundwater and shoreline contamination), blowouts, cratering, mechanical difficulties, fires, explosions, unusual or unexpected formation pressures, pollution and environmental hazards, each of which could result in damage to or destruction of oil and natural gas wells, production facilities or other property, or injury to persons. In addition, we are subject to other operating and production risks such as title problems, weather conditions, compliance with government permitting requirements, shortages of or delays in obtaining equipment, reductions in product prices, limitations in the market for products, litigation and disputes in the ordinary course of business. Although we maintain insurance coverage considered to be customary in the industry, we are not fully insured against certain of these risks either because such insurance is not available or because of high premium costs. We cannot predict if or when any such risks could affect our operations. The occurrence of a significant event for which we are not adequately insured could cause our actual results to differ from those reflected in our forward-looking statements.

Drilling Risks. Our decision to purchase, explore, develop or otherwise exploit a prospect or property will depend in part on the evaluation of data obtained through geophysical and geological analysis, production data and engineering studies, which are inherently imprecise. Therefore, we cannot assure you that all of our drilling activities will be successful or that we will not drill uneconomical wells. The occurrence of unexpected drilling results could cause the actual results to differ from those reflected in our forward-looking statements.

Uncertainties in Estimating Reserves and Future Net Cash Flows. Reserve engineering is a subjective process of estimating the recovery from underground accumulations of oil and natural gas we cannot measure in an exact manner, and the accuracy of any reserve estimate is a function of the quality of those accumulations of data and of engineering and geological interpretation and judgment. Reserve estimates are inherently imprecise and may be expected to change as additional information becomes available. There are numerous uncertainties inherent in estimating quantities and values of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. Because all reserve estimates are to some degree speculative, the quantities of oil and natural gas that we ultimately recover, production and operating costs, the amount and timing of future development expenditures and future oil and natural gas sales prices may differ from those assumed in these estimates. Significant downward revisions to our existing reserve estimates could cause the actual results to differ from those reflected in our forward-looking statements.

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Borrowing base for the Credit Facility. The Credit Agreement with Societe Generale and Fortis Capital Corp. is presently scheduled for borrowing base redetermination dates on a quarterly basis beginning April 30, 2003. The borrowing base is redetermined on numerous factors including current reserve estimates, reserves that have recently been added, current commodity prices, current production rates and estimated future net cash flows. These factors have associated risks with each of them. Significant reductions or increases in the borrowing base will be determined by these factors, which, to a significant extent, are not under the Company's control but largely dependent solely on the discretion of its lenders.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is currently exposed to market risk from hedging contracts changes and changes in interest rates. A discussion of the market risk exposure in financial instruments follows.

INTEREST RATES

We are subject to interest rate risk on our long-term fixed interest rate debt and variable interest rate borrowings. Our long-term borrowings primarily consist of borrowings under the Credit Facility and principal due December 31, 2004 under our Subordinated Credit Agreement. Since interest charged borrowings under the Credit Facility floats with prevailing interest rates (except for the applicable interest period for Eurodollar loans), the carrying value of borrowings under the Credit Facility should approximate the fair market value of such debt. Changes in interest rates, however, will change the cost of borrowing. Assuming $182.5 million remains borrowed under the Credit Facility and the Subordinated Credit Agreement, we estimate our annual interest expense will change by $1.825 million for each 100 basis point change in the applicable interest rates utilized. Changes in interest rates would, assuming all other things being equal, cause the fair market value of debt with a fixed interest rate, such as the Notes, to increase or decrease, and thus increase or decrease the amount required to refinance the debt. The fair value of the Notes is dependent on prevailing interest rates and our current stock price as it relates to the conversion price of $5.00 per share of our Common Stock.

HEDGING CONTRACTS

The Company may address market risk by selecting instruments whose value fluctuations correlate strongly with the underlying commodity being hedged. The Company enters into swaps and other derivative contracts to hedge the price risks associated with a portion of anticipated future oil and gas production. While the use of hedging arrangements limits the downside risk of adverse price movements, it may also limit future gains from favorable movements. Under these agreements, payments are received or made based on the differential between a fixed and a variable product price. These agreements are settled in cash at or prior to expiration or exchanged for physical delivery contracts. The Company does not obtain collateral to support the agreements, but monitors the financial viability of counter-parties and believes its credit risk is minimal on these transactions. In the event of nonperformance, the Company would be exposed to price risk. The Company has some risk of accounting loss since the price received for the product at the actual physical delivery point may differ from the prevailing price at the delivery point required for settlement of the hedging transaction.

The Company's results of operations and operating cash flows are impacted by changes in market prices for oil and natural gas. To mitigate a portion of the exposure to adverse market changes, the Company has entered into various swap agreements. These swaps allow the Company to predict with greater certainty the effective oil and natural gas prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

These swaps have been designated as cash flow hedges as provided by SFAS 133 and any changes in fair value of the cash flow hedge resulting from ineffectiveness of the hedge is reported in the consolidated statement of operations as revenues.

The estimated June 30, 2003, fair value of the Company's oil and natural gas swaps is an unrealized loss of $12.6 million ($8.2 million net of tax) recognized in other comprehensive income. Based upon June 30, 2003, oil and natural gas commodity prices, approximately $8.9 million of the loss deferred in other comprehensive income is expected to lower gross revenues over the next twelve months when the revenues are generated. The swap agreements expire at various dates through July 31, 2005.

Payments under these swap agreements reduced oil and natural gas revenues by

$3,026,000 for the three months and $10,131,000 for the six months ended June 30, 2003, as a result of hedging transactions.

The notional amount is equal to the total net volumetric hedge position of the Company during the periods presented. The positions effectively hedge approximately 19% of our proved developed natural gas production and 74% of our proved developed oil production. The fair values of the hedges are based on the difference between the strike price and the New York Mercantile Exchange future prices for the applicable trading months.

	Notional Amount	Weighted Average Strike Price ($ per unit)	Fair a
Natural Gas (mmbtu)			
July 2003 - June 2005	5,820,000	$ 3.77	$
Oil (bbls)			
July 2003 - July 2005	1,451,000	$ 24.04	$
			$

ITEM 4. CONTROLS AND PROCEDURES

Within the 90-day period prior to the filing of this report, an evaluation was conducted under the supervision and with the participation of Meridian's management, including our Chief Executive Officer and Chief Accounting Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-14(c) under the Securities Exchange Act of 1934). Based upon that evaluation, our Chief Executive Officer and Chief Accounting Officer concluded that the design and operation of our disclosure controls and procedures are effective. There have been no significant changes in our internal controls or in other factors that could significantly affect these controls subsequent to the date of our evaluation.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

On October 29, 2002, Veritas DGC Land Inc. ("Veritas Land") filed a complaint against Meridian. The dispute concerns a contract for seismic services for Meridian's Biloxi Marshlands project in St. Bernard Parish, Louisiana. Purporting to invoke force majeure, Veritas Land, together with Veritas DGC Inc. (collectively, "Veritas"), unilaterally terminated the parties' contract. The main dispute is whether Veritas had breached the parties' contract before the alleged force majeure events and/or when it terminated the contract; Meridian has not made any payments to Veritas under the parties' contract. Veritas' complaint seeks breach-of-contract damages of approximately $6.8 million together with interest, costs and attorneys' fees.

On December 23, 2002, Meridian filed an answer denying the relief sought by Veritas and asserting a counterclaim against Veritas (1) declaring that (i)

Meridian is not in breach of the parties' seismic contract, (ii) Meridian owes no amounts to Veritas under the parties' seismic contract or otherwise, (iii) Veritas materially breached the parties' contract, and (iv) Veritas Land is solidarily liable to Meridian for all liability of Veritas DGC Inc., and (2) seeking an award to Meridian of all attorneys' fees, court costs and other expenses, amounts and damages incurred or suffered (or to be incurred or suffered) by Meridian. On January 27, 2003, Veritas Land filed an answer to Meridian's counterclaim, generally denying the counterclaim and asserting various affirmative defenses thereto. Veritas DGC Inc. has not yet answered the counterclaim.

No scheduling order has yet been issued. The parties have not yet issued discovery to each other. Meridian intends to vigorously defend the claims against it and to vigorously prosecute its counterclaim.

There are no other material legal proceedings to which Meridian or any of its subsidiaries or partnerships is a party or to which any of its property is subject, other than ordinary and routine litigation incidental to the business of producing and exploring for crude oil and natural gas.

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K

(a) Exhibits

31.1 Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934, as amended.

31.2 Certification of President pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934, as amended.

31.3 Certification of Chief Accounting Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934, as amended.

32.1 Certification of Chief Executive Officer pursuant to Rule 13a-14(b) or Rule 15d-14(b) under the Securities Exchange Act of 1934, as amended, and 18 U.S.C. Section 1350.

32.2 Certification of President pursuant to Rule 13a-14(b) or Rule 15d-14(b) under the Securities Exchange Act of 1934, as amended, and 18 U.S.C. Section 1350.

32.3 Certification of Chief Accounting Officer pursuant Rule 13a-14(b) or Rule 15d-14(b) under the Securities Exchange Act of 1934, as amended, and 18 U.S.C. Section 1350.

(b) The Company filed no reports on Form 8-K during the second quarter of 2003.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

THE MERIDIAN RESOURCE CORPORATION AND SUBSIDIARIES
(Registrant)

Date: August 14, 2003

By: /s/ LLOYD V. DELANO
Lloyd V. DeLano
Senior Vice President
Chief Accounting Officer

INDEX TO EXHIBITS

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