MERIDIAN RESOURCE CORP
Form 10-Q
August 10, 2009

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549
FORM 10-Q

(Mark One)

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

For the quarterly period ended: June 30, 2009

OR

o **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 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files.) Yes o No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of large accelerated filer, accelerated filer, and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one)

Large accelerated filer o	Accelerated filer þ	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

Number of shares of common stock outstanding at August 3, 2009: 92,459,654

THE MERIDIAN RESOURCE CORPORATION
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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, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
REVENUES:				
Oil and natural gas	$ 22,710	$ 46,534	$ 44,819	$ 84,982
Price risk management activities	(5)	4	(3)	(30)
Interest and other	(16)	105	5	232
	22,689	46,643	44,821	85,184
OPERATING COSTS AND EXPENSES:				
Oil and natural gas operating	4,617	7,154	9,246	13,224
Severance and ad valorem taxes	1,989	2,996	3,624	5,574
Depletion and depreciation	9,371	17,886	21,134	35,628
General and administrative	4,287	5,215	7,656	9,290
Rig operations, net	1,839		1,839	
Contract settlement		9,894		9,894
Impairment of long-lived assets			59,539	
Accretion expense	554	531	1,077	1,098
	22,657	43,676	104,115	74,708
EARNINGS (LOSS) BEFORE INTEREST AND INCOME TAXES	32	2,967	(59,294)	10,476
OTHER EXPENSE:				
Interest expense	1,495	1,372	3,129	2,523
EARNINGS (LOSS) BEFORE INCOME TAXES	(1,463)	1,595	(62,423)	7,953
INCOME TAXES:				
Current Current	(1)	(96)		11
Deferred		852		3,540
	(1)	756		3,551
NET EARNINGS (LOSS)	$ (1,462)	$ 839	$ (62,423)	$ 4,402

NET EARNINGS (LOSS) PER SHARE:				
Basic	$ (0.02)	$ 0.01	$ (0.68)	$ 0.05
Diluted	$ (0.02)	$ 0.01	$ (0.68)	$ 0.05
WEIGHTED AVERAGE NUMBER OF COMMON SHARES:				
Basic	92,460	91,387	92,455	90,372
Diluted	92,460	94,501	92,455	94,901

See notes to consolidated financial statements.

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

	June 30, 2009 (unaudited)	December 31, 2008
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 3,683	$ 13,354
Restricted cash	67	9,971
Accounts receivable, less allowance for doubtful accounts of $210 [2009 and 2008]	11,852	16,980
Due from affiliates	2,081	
Prepaid expenses and other	3,080	3,292
Assets from price risk management activities	4,284	8,447
Total current assets	25,047	52,044
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, full cost method (including $19,035[2009] and $39,927 [2008] not subject to depletion)	1,889,238	1,877,925
Land	83	48
Equipment and other	20,514	21,371
	1,909,835	1,899,344
Less accumulated depletion and depreciation	1,727,419	1,647,496
Total property and equipment, net	182,416	251,848
OTHER ASSETS:		
Other	309	683
Total other assets	309	683
TOTAL ASSETS	$ 207,772	$ 304,575

See notes to consolidated financial statements.

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

	June 30, 2009 (unaudited)	December 31, 2008
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 8,746	$ 15,097
Advances from non-operators	11	5,517
Revenues and royalties payable	4,798	6,267
Due to affiliates		8,145
Notes payable	1,652	1,775
Accrued liabilities	12,671	18,831
Liabilities from price risk management activities	19	311
Asset retirement obligations	599	1,457
Current income taxes payable		47
Current maturities of long-term debt	102,453	103,849
Total current liabilities	130,949	161,296
LONG-TERM DEBT		
OTHER:		
Asset retirement obligations	21,661	20,768
COMMITMENTS AND CONTINGENCIES (Note 8)		
STOCKHOLDERS EQUITY:		
Common stock, $0.01 par value (200,000,000 shares authorized, 92,459,654 [2009] and 93,045,592 [2008] issued)	925	948
Additional paid-in capital	535,386	538,561
Accumulated deficit	(485,411)	(422,028)
Accumulated other comprehensive income	4,262	8,129
	55,162	125,610
Less treasury stock, at cost -0- [2009] and 1,712,114 [2008]shares		3,099
Total stockholders equity	55,162	122,511
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 207,772	$ 304,575

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 Months Ended June 30, 2009	Six Months Ended June 30, 2008
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net earnings (loss)	$ (62,423)	$ 4,402
Adjustments to reconcile net earnings (loss) to net cash provided by operating activities:		
Depletion and depreciation	21,134	35,628
Impairment of long-lived assets	59,539	
Amortization of other assets	374	85
Non-cash compensation	97	1,324
Non-cash gain on change in fair value of outstanding warrants	(399)	
Non-cash price risk management activities	3	30
Accretion expense	1,077	1,098
Deferred income taxes		3,540
Changes in assets and liabilities:		
Restricted cash	9,904	(9,895)
Accounts receivable	4,377	(6,334)
Prepaid expenses and other	212	(1,188)
Due to/from affiliates	(10,226)	12,350
Accounts payable	(2,280)	2,167
Advances from non-operators	(5,506)	(517)
Revenues and royalties payable	(1,469)	958
Asset retirement obligations	(81)	(627)
Other assets and liabilities	(4,865)	2,662
Net cash provided by operating activities	9,468	45,683
CASH FLOWS USED IN INVESTING ACTIVITIES:		
Additions to property and equipment	(17,442)	(72,720)
Proceeds from sale of property	17	4,502
Net cash used in investing activities	(17,425)	(68,218)
CASH FLOWS PROVIDED BY (USED IN) FINANCING ACTIVITIES:		
Proceeds from long-term debt		35,000
Reductions to long-term debt	(1,396)	(10,283)
Proceeds from notes payable	2,232	5,136
Reductions in notes payable	(2,355)	(3,524)
Payment of taxes due on vested stock	(195)	
Additions to deferred loan costs		(869)
Net cash provided by (used in) financing activities	(1,714)	25,460

NET CHANGE IN CASH AND CASH EQUIVALENTS	(9,671)	2,925
Cash and cash equivalents at beginning of period	13,354	13,526
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 3,683	$ 16,451

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	Six Months Ended June 30,	
	2009	2008
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION		
Increase (decrease) of Non-cash Activities:		
Accrual of capital expenditures	$ (5,221)	$ (10,248)
ARO liability additions to liabilities	$ 47	$ 50
ARO liability changes in estimates	$ (1,008)	$ (3,653)
Rig depreciation capitalized to oil and natural gas properties	$ 91	$ 488

See notes to consolidated financial statements.

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THE MERIDIAN RESOURCE CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY
Six Months Ended June 30, 2009 and 2008
(in thousands)
(unaudited)

	Common Stock Shares	Common Stock Par Value	Additional Paid-In Capital	Accumulated Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss)	Treasury Stock Shares	Treasury Stock Cost	Total
Balance, December 31, 2007	89,450	$ 936	$ 537,145	$ (212,142)	$ (221)	159	$ (288)	$ 325,430
Issuance of rights to common stock		3	(3)					
Company s 401(k) plan contributions			(3)			(72)	133	130
Stock-based compensation			92					92
Compensation expense			968					968
Accumulated other comprehensive income activity					(13,718)			(13,718)
Issuance of shares for contract services			26			(60)	108	134
Net earnings				4,402				4,402
Balance, June 30, 2008	89,450	$ 939	$ 538,225	$ (207,740)	$ (13,939)	27	$ (47)	$ 317,438
Balance, December 31, 2008	93,045	$ 948	$ 538,561	$ (422,028)	$ 8,129	1,712	$ (3,099)	$ 122,511
Effect of adoption of EITF Issue 07-05 (to record outstanding warrants at fair value)				(960)				(960)
Distribution of shares from Rabbi Trust:								

From treasury shares		(17)	(3,082)			(1,712)	3,099	
Repurchased in exchange for payment of withholding tax on vested stock						610	(195)	(195)
Retired	(610)	(6)	(189)			(610)	195	
Stock-based compensation	25		96					96
Accumulated other comprehensive income activity					(3,867)			(3,867)
Net loss				(62,423)				(62,423)
Balance, June 30, 2009	92,460	$ 925	$ 535,386	$ (485,411)	$ 4,262		$	$ 55,162

See notes to consolidated financial statements.

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THE MERIDIAN RESOURCE CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(thousands of dollars)
(unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Net earnings	$ (1,462)	$ 839	$ (62,423)	$ 4,402
Other comprehensive income (loss), net of tax, for unrealized gains (losses) from hedging activities:				
Unrealized holding gains (losses) arising during period (1)	(642)	(11,781)	3,156	(15,875)
Reclassification adjustments on settlement of contracts (2)	(3,452)	1,765	(7,023)	2,157
	(4,094)	(10,016)	(3,867)	(13,718)
Total comprehensive income (loss)	$ (5,556)	$ (9,177)	$ (66,290)	$ (9,316)
(1) net income tax (expense) benefit	$	$ 6,344	$	$ 8,548
(2) net income tax (expense) benefit	$	$ (951)	$	$ (1,162)

See notes to consolidated financial statements.

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THE MERIDIAN RESOURCE CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

1. BASIS OF PRESENTATION AND GOING CONCERN

The consolidated financial statements reflect the accounts of The Meridian Resource Corporation and its subsidiaries (the Company or Meridian) 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, 2008, as filed with the Securities and Exchange Commission (SEC).

The financial statements included herein as of June 30, 2009, and for the three month and six month periods ended June 30, 2009 and 2008, are unaudited, and in the opinion of management, the information furnished reflects all material adjustments, consisting of normal recurring adjustments, necessary for a fair presentation of financial position and of the results of operations for the interim periods presented. Certain minor reclassifications of prior period financial statements have been made to conform to current reporting practices. The results of operations for interim periods are not necessarily indicative of results to be expected for a full year.

On April 13, 2009, the lenders under the Company s credit facility notified the Company that, effective April 30, 2009, the borrowing base was reduced from its then-current and fully drawn $95 million to $60 million. The credit facility provides that outstanding borrowings in excess of the borrowing base must be repaid within 90 days after the redetermination. Accordingly, a $34.5 million payment to the lenders for the borrowing base deficiency was due July 29, 2009. The Company does not currently have sufficient cash available to repay the deficiency and, consequently, failed to pay such amount when due and is in default under the credit facility for such failure. The borrowing base is determined at the discretion of the lenders, based primarily on the value of the Company s proved reserves. In conjunction with the most recent borrowing base redetermination, the value of proved reserves was significantly reduced due to the precipitous decrease in the prices of oil and natural gas. Outstanding borrowings under the credit facility are $94.5 million at June 30, 2009 and August 10, 2009.

As of December 31, 2008 and June 30, 2009, the Company is also in default of certain covenants under its credit facility, including one that requires the Company to maintain a current ratio, as defined in the credit facility, of at least one to one. In addition, the Company was not in compliance with a covenant requiring that the Company s auditors opinion of its current financial statements be without modification. The Company s 2008 audit report from its independent registered accounting firm included a going concern explanatory paragraph that expressed substantial doubt about the Company s ability to continue as a going concern.

Because of the defaults, in accordance with the credit facility, the Company granted mortgages on certain producing properties that increase from not less than 75% to not less than 95% the amount of the present value of proved oil and natural gas properties that are secured by pledges to the lenders.

The Company has master derivative agreements with affiliates of two of the lenders under the credit facility, which, by virtue of the default under the credit facility, are also in default. See Notes 12 and 15 for further information on these commodity derivative contracts, which have been recorded as net assets of $4.3 million at June 30, 2009.

Under the terms of the credit facility, the lenders have various remedies available if they choose to declare a default, including acceleration of payment of all principal and interest. The Company is currently in discussions with the lenders and the affiliated hedge counterparties regarding entering into forbearance agreements pursuant to which such parties would forbear for an agreed period of time from exercising remedies otherwise available to them as a result of such existing covenant and payment defaults. No assurance can be provided that the lenders or hedge counterparties will agree to any such arrangements.

The Company is also in default of its other bank debt, a five-year $8.0 million loan (four years remaining of the term), which was used to purchase a drilling rig (rig note.) The lender under the rig note is CIT Group/Equipment Financing, Inc. (CIT.) Under the terms of the rig note, a default under the credit facility triggers a cross-default under the rig note. The remedies available to CIT under the rig note also include acceleration of all principal and interest payments. The Company is in discussions with CIT regarding a forbearance agreement under which CIT would forbear to exercise its default remedies for a specified period of time. The current proposal anticipates that, as a condition to the forbearance, the drilling rig, which serves as collateral under the rig note, would be transferred to a third party, with the third party providing a guarantee of the Company s payment obligations to CIT. There can be no assurance of the outcome of these discussions with CIT or any third party.

The Company is pursuing other options for repayment of its indebtedness, including the sale of strategic and nonstrategic assets or obtaining capital from other sources. The Company may not be able to sell assets on terms that management considers advantageous to the Company and its shareholders, and capital on acceptable terms may not be available from other sources. If the Company is unable to obtain concessions from the lenders under the credit facility, CIT, and the hedge counterparties, and execute a transfer of the drilling rig and execute other alternatives, the Company would continue to be in default under the credit facility, the rig note, and the hedge agreements and would be subject to the exercise of remedies by such parties on account of such defaults. The exercise of such remedies could potentially result in the Company seeking protection under federal bankruptcy laws. Such relief could materially and adversely affect the Company and its shareholders.

In addition to liquidity issues related to bank debt and working capital, the Company has significant obligations under two long term dayrate drilling rig contracts. These obligations, described more fully in Note 8, place a significant burden on cash flow in the immediate future. The forbearance agreement under discussion with CIT would release the Company from liability under these drilling contracts.

2. SIGNIFICANT ACCOUNTING POLICIES

Rig Operations

The Company has a long-term dayrate contract to utilize a drilling rig from an unaffiliated service company, Orion Drilling, Ltd, (Orion). Although capital expenditure plans no longer accommodate full use of this rig, the Company is obligated for the dayrate regardless of whether the rig is working or idle. When the contracted rig is not in use on Meridian-operated wells, Orion may contract it to third parties, or the rig may be idled. The Company is obligated for the difference in dayrates if it is utilized by a third party at a lesser dayrate. The contracted rig was utilized drilling a Meridian-operated well through the end of the first quarter of 2009, and contracted to a third party during the second quarter at a lesser dayrate than the Company s. The costs of the rig when it is not providing services to the Company have been included in the consolidated statements of operations as Rig operations, net.

TMR Drilling Corporation (TMRD), a wholly owned subsidiary of the Company, owns a rig which was also intended primarily to drill wells operated by the Company. In April 2008, Orion began leasing the rig from TMRD, and operating it under a dayrate contract with the Company. When the rig drills Company wells, drilling expenditures under the dayrate contract are capitalized as exploration costs. All TMRD profits or losses related to lease of the rig, including any incidental profits related to the share of drilling costs borne by joint interest partners, are offset against the full cost pool. From April through December of 2008, the rig was utilized almost continuously on Company wells and its profits were accordingly capitalized. For the three and six month periods ending June 30, 2008, the rig profits capitalized to the full cost pool were $148,000. For the three and six month periods ending June 30, 2009, the rig profits capitalized to the full cost pool were $180,000.

When the rig is used by Orion for work on third party wells in which the Company has no economic or management interest, TMRD s profit or loss related to the lease of the rig is reflected in the consolidated statements of operations. During the six months ended June 30, 2009, the rig worked on third party wells. As with the rig separately under contract from Orion, the Company is obligated for the difference in dayrates if it is not utilized or is utilized by a third party at a lesser dayrate, which has occurred during 2009. This loss on a contractual obligation is included in Rig Operations, net in the consolidated statements of operations. The Company s share of profits on the lease of the rig to Orion partially offsets the loss on the drilling contract and is included in Rig operations, net on the consolidated statements of operations. The total lease revenue included in Rig operations, net for the three and six month periods ended June 30, 2009 was $645,000.

In addition, depreciation expense on the owned rig of $221,000 and $369,000 for the three and six month periods ended June 30, 2009, respectively, was included in Depletion and depreciation expense on the consolidated statements of operation.

See Notes 1 and 8 for additional information on the Company s plans for potential disposition of the rig and the obligations under the drilling contracts.

Property and Equipment

The Company uses the full cost method of accounting for its investments in oil and natural gas properties. Capitalized costs of proved oil and natural gas properties are depleted on a units of production method using proved oil and natural gas reserves. Costs depleted include net capitalized costs subject to depletion and estimated future dismantlement, restoration, and abandonment costs. All costs incurred in the acquisition, exploration, and development of oil and natural gas properties, including unproductive wells, are capitalized. Through March 2009, capitalized costs included general and administrative costs directly related to acquisition, exploration and development activities. Subsequent to that date, no general and administrative costs have been capitalized, as such activities have significantly decreased. The Company expects to capitalize general and administrative costs in the future, when costs related directly to the acquisition, exploration, and development of oil and natural gas properties are incurred. Total general and administrative costs capitalized were zero and $2.6 million for the three and six month periods ended June 30, 2009, and $3.9 million and $8.3 million for the three and six month periods ended June 30, 2008.

Equipment, which includes a drilling rig, computer equipment, computer hardware and software, furniture and fixtures, leasehold improvements and automobiles, is recorded at cost and is generally depreciated on a straight-line basis over the estimated useful lives of the assets, which range in periods of three to seven years.

Restricted Cash, Rabbi Trust, and Treasury Stock

The Company classifies cash balances as restricted when cash is restricted as to withdrawal or usage. The restricted cash balance at December 31, 2008, was $9,971,000 and at June 30, 2009, was $67,000. Restricted cash increased by $9,894,000 in May 2008, when contractual obligations to two former executive officers were funded by cash placed in a Rabbi Trust account. Additional restricted cash relates to a contractual royalties payable obligation.

The obligations to the former executive officers included an obligation to pay them a total of $9.9 million in cash, and 1.7 million shares of common stock of the Company, based on agreements effective in April

2008, which terminated their employment agreements and certain other compensation-related agreements. Pursuant to the contractual terms, both the shares and the cash from the trust were distributed to the former officers upon dissolution of the trust during the second quarter of 2009. The shares in the trust were accounted for as treasury shares so long as they remained in the trust. Until distribution, the assets of the trust belonged to the Company, but were effectively restricted due to the obligation to the former officers.

As of June 30, 2009, the Company had no remaining shares in treasury.

Fair Value of Financial Instruments

Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable and bank borrowings. The carrying amounts of cash and cash equivalents, accounts receivable, accounts payable, and accrued liabilities approximate fair value due to the highly liquid nature of these short-term instruments. As of June 30, 2009 the Company believes it is not practicable to estimate the fair value of its outstanding debt under the credit facility in light of the payment default. The reduction in credit standing from this default would certainly tend to reduce the fair value of the debt, but it is not practicable to estimate the amount of such reduction. The carrying value of that debt is $94.5 million. See Note 6 for further details on the credit facility. The Company also has a smaller bank debt with a fixed rate, the rig note. The fair value of the rig note at June 30, 2009 is estimated as approximately $5 million; the corresponding carrying value is $8.0 million. The fair value was estimated based on the fair value of the underlying collateral. The collateral is a drilling rig owned by the Company; see Note 6 for further information on how fair value for the rig was estimated. The rig note is in covenant default, but not in payment default.

Our oil and gas price risk hedging contracts are also financial instruments, recorded at fair value; see Note 12.

Subsequent Events

The Company reviews events occurring after the balance sheet date which could affect the financial position and / or results of operations for the period. The Company continues to review and evaluate events through date on which the financial statements are issued, which, for the three month and six month periods ending June 30, 2009, is August 10, 2009. See Note 15.

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Recent Accounting Pronouncements

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities, which amends FASB Statement No. 133 (SFAS 161). SFAS 161 provides guidance for additional disclosures regarding derivative contracts, including expanded discussions of risk and hedging strategy, as well as new tabular presentations of accounting data related to derivative instruments. The Company adopted SFAS 161 on January 1, 2009, and the additional disclosures are included in Note 12.

In June 2008, the FASB Emerging Issues Task Force (EITF) issued EITF Abstract Issue No. 07-05, Determining Whether an Instrument (or Embedded Feature) Is Indexed to an Entity s Own Stock (EITF 07-05). The issue clarifies the determination of equity instruments which may qualify for an exemption from SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. Generally, equity instruments which qualify under the guidelines of EITF 07-05 may be accounted for in equity accounts; those which do not qualify are subject to derivative accounting. We adopted the guidance of EITF 07-05 on January 1, 2009. The effects of the adoption included a revision in the carrying value of certain outstanding warrants, and recognition of a related liability on January 1, 2009, as well as recognition of an unrealized gain due to the change in fair value of those warrants during the first quarter of 2009. See Note 9 for further information.

In December 2008, the Securities and Exchange Commission published a Final Rule, Modernization of Oil and Gas Reporting. The new rule permits the use of new technologies to determine proved reserves if those technologies have been demonstrated to lead to reliable conclusions about reserves volumes. The new requirements also will allow companies to disclose their probable and possible reserves to investors. In addition, the new disclosure requirements require companies to, among other things: (*a*) report the independence and qualifications of its reserves preparer or auditor; (*b*) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserves audit; and (*c*) report oil and gas reserves using an average price based upon the prior 12-month period rather than period-end prices. The use of the new proved reserve definitions and average prices in developing the Company s reserve estimates will affect future impairment and depletion calculations.

The new disclosure requirements are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. A company may not apply the new rules to disclosures in quarterly reports prior to the first annual report in which the revised disclosures are required. The Company has not yet determined the impact of this Final Rule on its disclosures, financial position, or results of operations; the effect of the changes will vary depending on changes in commodity prices.

In April 2009, the FASB issued FASB Staff Position FSP FAS 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments, which enhances consistency in financial reporting by increasing the frequency of fair value disclosures. The guidance is effective for interim and annual periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. The Company adopted FSP FAS 107-1 and APB 28-1 effective April 1, 2009. The adoption did not have a material impact on financial position or results of operations of the Company. The additional disclosures are included above, Fair Value of Financial Instruments.

In May 2009, the FASB issued SFAS 165, Subsequent Events (SFAS 165). SFAS 165 defines the period during which management should evaluate events or transactions that occur after the balance sheet date for potential recognition or disclosure in the financial statements, the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date, and the disclosures about such subsequent events. It does not substantially change current guidance, but adds a new disclosure of the date through which events have been evaluated and whether that is the date of issuance of the financial statements or an alternate date. SFAS 165 is effective for interim or annual financial periods ending after June 15, 2009. The Company adopted SFAS 165 effective June 30, 2009; the adoption did not have a material impact on financial position or results of operations of the Company.

Also in June 2009, the FASB issued SFAS 167, Amendments to FASB Interpretation No. 46(R) a revision of FIN 46, Consolidation of Variable Interest Entities (FIN 46(R)), which amends existing consolidation guidance for variable interest entities (VIE s). Variable interest entities generally are thinly-capitalized entities which under previous guidance may not have been consolidated. The new standard requires a company to perform a qualitative analysis to determine whether to consolidate a VIE, which includes consideration of control issues other than the primarily quantitative considerations utilized

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prior to this revision. In addition, the new standard requires ongoing assessments of whether to consolidate VIE s, rather than only when specific events occur. The new standard also requires additional disclosures about consolidated and unconsolidated VIE s, including their impact on the company s risk exposure and its financial statements. SFAS 167 will be effective for financial statements for annual and interim periods beginning after November 15, 2009. The Company does not expect the adoption to have a material impact on financial position or results of operations.

In July 2009, the FASB issued Statement No. 168, The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles (SFAS 168), which supersedes and replaces Statement No. 162, The Hierarchy of Generally Accepted Accounting Principles . Under SFAS 168, the FASB Accounting Standards Codification (Codification), the FASB s new web-based codification of accounting and reporting guidance, along with guidance provided by the SEC, will be the only authoritative sources of such guidance. All guidance not contained in the Codification, other than Securities and Exchange Commission (SEC) guidance, will be considered non-authoritative. The Codification is designed to incorporate previously issued guidance from sources such as the FASB, the American Institute of Certified Public Accountants, and the Public Company Accounting Oversight Board, and is not intended to change GAAP for non-governmental entities. SFAS 168 provides additional guidance on the selection, interpretation, and application of accounting principles from the Codification and from non-authoritative sources when necessary. The statement will be effective for financial statements issued for interim and annual periods ending after September 15, 2009. The Company does not expect the adoption to have a material impact on financial position or results of operations.

3. IMPAIRMENT OF LONG-LIVED ASSETS

At the end of each quarter, the unamortized cost of oil and natural gas properties, net of related deferred income taxes, is limited to the sum of the estimated future after-tax net revenues from proved properties using period-end prices, after giving effect to cash flow hedge positions, discounted at 10% (the ceiling), and the lower of cost or fair value of unproved properties adjusted for related income tax effects.

Accordingly, based on March 31, 2009 pricing of $3.76 per Mcfe of natural gas and $49.66 per barrel of oil, the Company recognized a non-cash impairment of $59.5 million of the Company s oil and natural gas properties under the full cost method of accounting during the first quarter of 2009.

Due to the substantial volatility in oil and natural gas prices and their effect on the carrying value of the Company s proved oil and natural gas reserves, there can be no assurance that future write-downs will not be required as a result of factors that may negatively affect the present value of proved oil and natural gas reserves and the carrying value of oil and natural gas properties, including volatile oil and natural gas prices, downward revisions in estimated proved oil and natural gas reserve quantities, and unsuccessful drilling activities.

Based on June 30, 2009 prices for oil and natural gas, the Company had an excess of the ceiling over our capitalized costs. See Note 8 for further information regarding the sensitivity of the ceiling to changes in the prices of oil and natural gas.

4. FAIR VALUE MEASUREMENT

The Company adopted the provisions of SFAS 157, effective January 1, 2008. SFAS 157 does not expand the use of fair value measurements, but rather, provides a framework for consistent measurement of fair value for those assets and liabilities already measured at fair value under other accounting pronouncements. Certain specific fair value measurements, such as those related to share-based

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compensation, are not included in the scope of SFAS 157. Primarily, SFAS 157 is applicable to assets and liabilities related to financial instruments, to some long-term investments and liabilities, to initial valuations of assets and liabilities acquired in a business combination, and to long-lived assets for which an impairment write-down to a fair value must be made. It does not apply to oil and natural gas properties accounted for under the full cost method, which are subject to impairment based on SEC rules. SFAS 157 applies to assets and liabilities carried at fair value on the consolidated balance sheet, as well as to supplemental fair value information about financial instruments not carried at fair value, which the Company provides quarterly under the provisions of FSP FAS 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments, effective the second quarter of 2009.

Certain provisions of SFAS 157 were deferred by the FASB. On January 1, 2009, the Company adopted the provisions of SFAS 157 for those non-financial assets and liabilities which are measured at fair value on a non-recurring basis. This includes new additions to asset retirement obligations, and any long-lived assets, other than oil and natural gas properties, for which an impairment write-down is recorded during the period. There have been no such impairments of long-lived assets in the current period.

The Company adopted the provisions of SFAS 157 as it applies to assets and liabilities measured at fair value on a recurring basis on January 1, 2008. This included oil and natural gas derivatives contracts, and as of January 1, 2009, certain outstanding warrants known as the General Partner Warrants (see Notes 2 and 9).

SFAS 157 provides a definition of fair value and a framework for measuring fair value, as well as expanding disclosures regarding fair value measurements. The framework requires fair value measurement techniques to include all significant assumptions that would be made by willing participants in a market transaction. These assumptions include certain factors not consistently provided for previously by those companies utilizing fair value measurement; examples of such factors would include the company s own credit standing (when valuing liabilities) and the buyer s risk premium. In adopting SFAS 157, the Company determined that the impact of these additional assumptions on fair value measurements did not have a material effect on financial position or results of operations.

SFAS 157 provides a hierarchy of fair value measurements, based on the inputs to the fair value estimation process. It requires disclosure of fair values classified according to the levels described below. The hierarchy is based on the reliability of the inputs used in estimating fair value. The framework for fair value measurement assumes that transparent observable (Level 1) inputs generally provide the most reliable evidence of fair value and should be used to measure fair value whenever available. The classification of a fair value measurement is determined based on the lowest level (with Level 3 as lowest) of significant input to the fair value estimation process.

> Level 1 fair values are based on observable inputs. Observable inputs are quoted active market prices for assets and liabilities identical to those being valued.
>
> Level 2 fair values are based on observable inputs for similar assets and liabilities to those being valued. Level 2 fair values often rely on valuation models for which the significant inputs are observable Level 1 inputs, or inputs which can be derived from Level 1 inputs through correlation.
>
> Level 3 fair values are based on at least one significant unobservable input, and may also utilize observable inputs. Unobservable inputs must be utilized when the asset or liability being valued is not actively traded. Level 3 fair values rely on valuation models that may utilize company-specific information or other unobservable inputs, developed based on the best information available in the circumstances.

The Company utilizes the modified Black-Scholes option pricing model to estimate the fair value of oil

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and natural gas derivative contracts. Inputs to this model include observable inputs from the New York Mercantile Exchange (NYMEX) for futures contracts, and inputs derived from NYMEX observable inputs, such as implied volatility of oil and gas prices. The Company has classified the fair values of all its derivative contracts as Level 2. The fair value of the Company s general partner warrants (see Notes 2 and 9) was calculated using the Black-Scholes option pricing model.

Assets and liabilities measured at fair value on a recurring basis

			Fair Value Measurements at June 30, 2009 Using (thousands of dollars)		
Description		June 30, 2009	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)
Assets from price risk management activities	(1)	$4,284		$ 4,284	
Liabilities from price risk management activities	(1)	$ 19		$ 19	
General partner warrants	(2)	$ 562		$ 562	

(1) Assets and liabilities from price risk management activities are oil and natural gas derivative contracts, in the form of costless collars to sell oil and natural gas within specific future time periods. These contracts are more fully described in Note 12.

(2)

General partner warrants are more fully described in Note 9.

As noted above, SFAS 157 also applies to new additions to asset retirement obligations, which must be estimated at fair value when added. New additions may result from increases to estimations of existing obligations or from estimations for new obligations for new properties, and fair values for them would be categorized as Level 3. Such estimations are based on present value techniques which utilize company-specific information. The Company recorded $47,000 in additions to asset retirement obligations measured at fair value during the three and six months ended June 30, 2009.

5. ACCRUED LIABILITIES

Below is the detail of accrued liabilities on the Company s balance sheets as of June 30, 2009 and December 31, 2008 (thousands of dollars):

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	June 30, 2009	December 31, 2008
Capital expenditures	$ 6,323	$ 8,227
Operating expenses/taxes	4,188	4,452
Hurricane damage repairs	410	1,555
Compensation	160	2,478
Interest	27	261
General partner warrants	562	
Other	1,001	1,858
Total	$ 12,671	$ 18,831

6. DEBT

***Credit Facility*.** On December 23, 2004, the Company amended its credit facility to provide for a four-year $200 million senior secured credit facility (the Credit Facility) with Fortis Capital Corp., as administrative agent, sole lead arranger and bookrunner; Comerica Bank as syndication agent; and Union Bank of California as documentation agent. Bank of Nova Scotia, Allied Irish Banks PLC, RZB Finance LLC and Standards Bank PLC completed the syndication group. The initial borrowing base under the Credit Facility was $130 million.

On February 21, 2008, the Company amended the Credit Facility. The lending institutions under the amended Credit Facility include Fortis Capital Corp. as administrative agent, co-lead arranger and bookrunner; The Bank of Nova Scotia, as co-lead arranger and syndication agent; Comerica Bank, US Bank NA and Allied Irish Bank plc each in their respective capacities as lenders (collectively, the Lenders.) The maturity date was extended to February 21, 2012, and the borrowing base was redetermined to be $110 million. Interest rates were slightly increased by increasing the range of the add-on to the prime base rate by 25 basis points on the lower end of the range and by 50 basis points on the higher end of the range; the range of the add-on to the alternative base rate was increased by 25 basis points on the higher end of the range.

On December 19, 2008, the Company entered into the Second Amendment to Credit Agreement to the Credit Facility (Second Amendment). The Second Amendment redetermined the borrowing base at $95 million, limiting borrowing to the amount outstanding at December 31, 2008. In addition, interest rates were increased by increasing the range of the add-on to the prime base rate by 50 basis points on the lower end of the range and by 75 basis points on the higher end of the range; the range of the add-on to the alternative base rate was increased by the same amounts.

The Credit Facility is subject to semi-annual borrowing base redeterminations on April 30 and October 31 of each year. In addition to the scheduled semi-annual borrowing base redeterminations, the Lenders or the Company have the right to redetermine the borrowing base at any time, provided that no party can request more than one such redetermination between the regularly scheduled borrowing base redeterminations. The determination of the borrowing base is subject to a number of factors, including quantities of proved oil and natural gas reserves, the banks price assumptions and other various factors unique to each member bank. The Lenders can redetermine the borrowing base to a lower level than the current borrowing base if they determine that the Company s oil and natural gas reserves, at the time of redetermination, are inadequate to support the borrowing base then in effect. In the event the redetermined borrowing base is less than outstanding borrowings under the Credit Facility, the Company will be required to repay the deficit within a 90-day period.

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On April 13, 2009, the Lenders notified the Company that, effective April 30, 2009, the borrowing base was reduced from its then-current and fully drawn $95 million to $60 million. The Credit Facility provides that outstanding borrowings in excess of the borrowing base must be repaid within 90 days after the redetermination. Accordingly, a $34.5 million payment to the Lenders for the borrowing base deficiency was due July 29, 2009. The Company does not currently have sufficient cash available to repay the deficiency and, consequently, failed to pay such amount when due and is in default under the Credit Facility for such failure.

The terms of the Credit Facility contain numerous covenants and restrictions. Currently, the Company is also in default of certain covenants, including one that requires that the Company maintain a current ratio (as defined in the Credit Facility) of one to one. The current ratio, as defined, was less than the required one to one at December 31, 2008, March 31, 2009, and June 30, 2009. The Company is also in default of the requirement that the Company s auditors opinion for the current financial statements be without modification. The Company s 2008 audit report from its independent registered accounting firm included a going concern explanatory paragraph that expressed substantial doubt about the Company s ability to continue as a going concern. As a result of the defaults, the outstanding Credit Facility balance of $95 million at December 31, 2008 and $94.5 million at June 30, 2009 has been classified in current liabilities on the accompanying consolidated balance sheets.

Under the terms of the Credit Facility, the Lenders have various remedies available in the event of a default, including acceleration of payment of all principal and interest. The Company is currently in discussions with the Lenders regarding entering into a forbearance agreement pursuant to which such parties would forbear for an agreed period of time from exercising remedies otherwise available to them as a result of the Company s covenant and payment defaults. No assurance can be provided that the Lenders will agree to any such arrangements.

Obligations under the Credit Facility are secured by pledges of outstanding capital stock of the Company s subsidiaries and by a first priority lien on not less than 75% (95% in the case of an event of default) of its present value of proved oil and natural gas properties. In addition, the Company is required to deliver to the Lenders and maintain satisfactory title opinions covering not less than 70% of the present value of proved oil and natural gas properties. Because of the defaults, in accordance with the Credit Facility, the Company has granted mortgages on certain of its producing properties that increase from not less than 75% to not less than 95% the amount of the present value of proved oil and natural gas properties that are secured by pledges to the Lenders.

The Credit Facility also contains other restrictive covenants, including, among other items, maintenance of certain financial ratios, restrictions on cash dividends on common stock and under certain circumstances preferred stock, limitations on the redemption of preferred stock, limitations on repurchases of common stock, restrictions on incurrence of additional debt, and an unqualified audit report on the Company s consolidated financial statements. As noted above, at December 31, 2008 and June 30, 2009, the Company was in default of certain of these covenants, as well as the payment default by failure to repay principal after the reduction of the borrowing base. Under the Credit Facility, the Company may secure either (i) (a) an alternative base rate loan that bears interest at a rate per annum equal to the greater of the administrative agent s prime rate; or (b) federal funds-based rate plus 1/2 of 1%, plus an additional 1.25% to 2.50% depending on the ratio of the aggregate outstanding loans and letters of credit to the borrowing base 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 2.0% to 3.25%, depending on the ratio of the aggregate outstanding loans and letters of credit to the borrowing base. At December 31, 2008, the three-month LIBOR interest rate was 1.425%; at June 30, 2009 it was 0.6%, and the prime rate remained at 3.25%. During the first quarter of 2009, the Lenders informed the Company that all outstanding tranches of debt would be converted to prime-based from LIBOR-based upon maturity. The Credit Facility continues to provide for commitment fees of 0.375% calculated on the difference between the borrowing base and the aggregate outstanding loans and letters of credit under the agreements. As of July 1, 2009, outstanding borrowing under the Credit Facility totaled $94.5 million.

As of June 30, 2009 the Company believes it is not practicable to estimate the fair value of its outstanding debt under the Credit Facility in light of the payment default. The reduction in credit standing from this default would certainly tend to reduce the fair value of the debt, but it is not practicable to estimate the amount of such reduction.

Rig Note. On May 2, 2008, the Company, through its wholly owned subsidiary TMRD, entered into a financing agreement with The CIT Group/Equipment Financing, Inc. (CIT). Under the terms of the agreement, TMRD borrowed $10.0 million, at a fixed interest rate of 6.625%, in order to refinance the purchase of a land-based drilling rig to be used in Company operations. The rig had been purchased using cash on hand and funds available to the Company under the Credit Facility. Funds from the new agreement were used to reduce borrowing under the Credit Facility. The loan is collateralized by the drilling rig, as well as general corporate credit. The term of the loan is five years; monthly payments of $196,248 for interest and principal are to be made until the loan is completely repaid at termination of the agreement on May 2, 2013.

Effective as of December 31, 2008, the Company is in default under the rig note. Under the terms of the rig note, a default under the Credit Facility triggers a cross-default under the rig note. The remedies available to CIT in the event of default include acceleration of all principal and interest payments. Accordingly, all indebtedness under the rig note, $8.8 million at December 31, 2008 and $8.0 million at June 30, 2009, has been classified in current liabilities on the accompanying consolidated balance sheets.

The Company is in discussions with CIT regarding a forbearance agreement under which CIT would forbear to exercise its default remedies for a specified period of time. The current proposal anticipates that, as a condition to the forbearance, the secured drilling rig would be transferred to a third party, with the third party providing a guarantee of the Company s payment obligations to CIT. There can be no assurance of the outcome of these discussions with CIT or any third party. The third party under consideration is the party to whom the Company is obligated under certain drilling contracts as described in Note 2, Rig Operations. The Company would obtain release of those obligations under the forbearance agreement in discussion with CIT, in exchange for transfer of the rig.

The fair value of the rig note balance at June 30, 2009 is estimated as approximately $5 million. This estimate was based on the fair value of the underlying collateral, which is a drilling rig owned by the Company. Fair value for the rig was estimated based on the present value of estimated cash flows from the rig, using conservative estimates of utilization and dayrates.

7. INCOME TAXES

The Company s effective income tax rate has varied significantly in recent periods. In the second quarter of 2008, the effective income tax rate was 47%, which is higher than the corporate income tax rate of 35% primarily due to state taxes and other permanent differences. In the fourth quarter of 2008 and the first quarter of 2009, the Company recorded significant non-cash impairment losses (see Note 3). U. S. GAAP requires a valuation allowance to be recognized if, based on the weight of available evidence, it is more likely than not that some portion or all of the deferred tax asset will not be realized. The Company does not expect to realize its deferred tax assets, and therefore recorded a valuation allowance as of December 31, 2008 to the full extent of all net deferred tax assets. The allowance was adjusted in the first six months of 2009 to maintain this complete offset of all deferred tax assets. Thus, the tax benefit related to net losses recognized in the first and second quarters of 2009 was zero, and the effective tax rate for the first six months is 0%.

In 2009, the Internal Revenue Service audited Meridian s 2006 and 2007 tax returns. The Company has received notification from the Internal Revenue Service indicating the audits are complete and there will be no changes to the Company s tax returns.

8. COMMITMENTS AND CONTINGENCIES

Litigation

H. L. Hawkins litigation. In December 2004, the estate of H.L. Hawkins filed a claim against Meridian for damages estimated to exceed several million dollars for Meridian s alleged gross negligence, willful misconduct and breach of fiduciary duty under certain agreements concerning certain wells and property in the S.W. Holmwood and E. Lake Charles Prospects in Calcasieu Parish in Louisiana, as a result of Meridian s satisfying a prior adverse judgment in favor of Amoco Production Company. Mr. James Bond had been added as a defendant by Hawkins claiming Mr. Bond, when he was General Manager of Hawkins, did not have the right to consent, could not consent or breached his fiduciary duty to Hawkins if he did consent to all actions taken by Meridian. Mr. James T. Bond was employed by H.L. Hawkins Jr. and his companies as General Manager until 2002. He served on the Board of Directors of the Company from March 1997 to August 2004. After Mr. Bond s employment with Mr. Hawkins, Jr., and his companies ended, Mr. Bond was engaged by The Meridian Resource & Exploration LLC as a consultant. This relationship continued until his death. Mr. Bond was also the father-in-law of Michael J. Mayell, the Chief Operating Officer of the Company at the time. A hearing was held before Judge Kay Bates on April 14, 2008. Judge Bates granted Hawkins Motion finding that Meridian was estopped from arguing that it did not breach its contract with Hawkins as a result of the United States Fifth Circuit s decision in the *Amoco* litigation. Meridian disagrees with Judge Bates ruling but the Louisiana First Court of Appeal declined to hear Meridian s writ requesting the court overturn Judge Bates ruling. Meridian filed a motion with Judge Bates asking that the ruling be made a final judgment which would give Meridian the right to appeal immediately; however, the Judge declined to grant the motion, allowing the case to proceed to trial. Management continues to vigorously defend this action on the basis that Mr. Hawkins individually and through his agent, Mr. Bond, agreed to the course of action adopted by Meridian and further that Meridian s actions were not grossly negligent, but were within the business judgment rule. Since Mr. Bond s death, a pleading has been filed substituting the proper party for Mr. Bond. The Company is unable to express an opinion with respect to the likelihood of an unfavorable outcome of this matter or to estimate the amount or range of potential loss should the outcome be unfavorable. Therefore, the Company has not provided any amount for this matter in its financial statements at June 30, 2009.

Parsons Exploration litigation. On May 3, 2007, Parsons Exploration Company, LLC (Parsons) filed a claim against Meridian for damages and specific performance requiring Meridian to assign Parsons an overriding royalty interest in certain wells the Company has drilled in east Texas. The complaint alleged that the Company breached its contractual and fiduciary obligations to Parsons under an Exploration and Prospect Origination Agreement between the parties dated April 22, 2003. The complaint also alleged that the Company engaged in a civil conspiracy to breach its contractual and fiduciary obligations to Parsons and tortiously interfered with existing and prospective business relationships/contracts of Parsons. The Company recognized an estimated settlement for this matter in the amount of $2.1 million in the first quarter of 2009, which was charged to the full cost pool. The parties reached a final confidential settlement agreement in the second quarter of 2009.

Environmental litigation. Various landowners have sued Meridian (along with numerous other oil companies) in lawsuits concerning several fields in which the Company has had operations. The lawsuits seek injunctive relief and other relief, including unspecified amounts in both actual and punitive damages for alleged breaches of mineral leases and alleged failure to restore the plaintiffs lands from alleged contamination and otherwise from the Company s oil and natural gas operations. In some of the lawsuits, Shell Oil Company and SWEPI LP (together, Shell) have demanded contractual indemnity and defense from Meridian based upon the terms of the two acquisition agreements related to the fields, and in another lawsuit, Exxon Mobil Corporation has demanded contractual indemnity and defense from Meridian on the basis of a purchase and sale agreement related to the field(s) referenced in the lawsuit; Meridian has challenged such demands. In some cases, Meridian has also demanded defense and indemnity from their subsequent purchasers of the fields. On December 9, 2008 Shell sent Meridian a letter reiterating its demand for indemnity. Shell has not to date produced all of the supporting documentation for its claim. Shell initiated formal arbitration proceedings on May 11, 2009, seeking relief only for the claimed costs and expenses arising from one of the two acquisition agreements between Shell and Meridian. An arbitration panel has been selected and an initial conference was held with the panel on July 31, 2009. The two companies have entered into settlement discussions. Meridian denies that it owes any indemnity under either of the two acquisition agreements; however, the amounts claimed are substantial in nature and if adversely determined, would have a material adverse effect on the Company. The Company is unable to express an opinion with respect to the likelihood of an unfavorable outcome of these matters or to estimate the amount or range of potential loss should any outcome be unfavorable. Therefore, the Company has not provided any amount for these matters in its financial statements at June 30, 2009.

Title/lease disputes. Title and lease disputes may arise in the normal course of the Company s operations. These disputes are usually small but could result in changes in reserves or require cash consideration, once a final resolution to the title dispute is made.

Litigation involving insurable issues. There are no material legal proceedings involving insurable issues which exceed insurance limits to which Meridian or any of its subsidiaries 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.

Other contingencies

Ceiling Test. At the end of each quarter, the unamortized cost of oil and natural gas properties, net of related deferred income taxes, is limited to the sum of the estimated future after-tax net revenues from proved properties using period-end prices, after giving effect to cash flow hedge positions, discounted at 10%, and the lower of cost or fair value of unproved properties adjusted for related income tax effects. This is known as the ceiling test. The Company recorded significant impairment charges against oil and gas properties based on the results of the ceiling test in the fourth quarter of 2008 and again in the first quarter of 2009.

At June 30, 2009, the Company had a cushion (i.e., the excess of the ceiling over capitalized costs) of approximately $30.4 million (pretax and after-tax). A 10% increase in prices would have increased the cushion by approximately 92%. A 10% decrease in prices would have decreased the cushion by approximately 91%. Decreases in prices affecting the end of subsequent accounting periods, net of the effect of the Company s hedging positions, may necessitate additional impairment charges. Any future impairment would be impacted by changes in the accumulated costs of oil and natural gas properties, which may in turn be affected by sales or acquisitions of properties and additional capital expenditures. Future impairment would also be impacted by changes in estimated future net revenues, which are impacted by additions and revisions to oil and natural gas reserves, as well as by sales and acquisitions of properties.

Due to the redetermination of the borrowing base under the Credit Facility, the Company is considering sales of assets to generate cash for repayment of debt. Sales of significant assets would impact future ceiling tests, as their estimated future after-tax net revenues would be removed from the calculation. Proceeds from sales of properties are generally credited to the full cost pool, reducing the carrying value of oil and gas properties subject to the ceiling test. The Company cannot predict whether significant property sales will cause additional ceiling test impairments, but it is possible that they will.

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Hurricane damages. Certain oil and natural gas properties sustained physical damage during two hurricanes in the third quarter of 2008, hurricane Gustav and hurricane Ike. The accompanying balance sheet includes a $461,000 insurance receivable at June 30, 2009, based on the most current information available. Damage estimates for non-operated properties are subject to revision. Also, additional information regarding non-operated properties may be obtained which bears on the applicability of insurance deductibles, and may also require revision to loss estimates.
Drilling rigs. The Company has significant contractual obligations for the use of two drilling rigs. The Company s capital expenditure plans no longer include full use of these rigs; however, the Company is obligated for the dayrate regardless of whether the rigs are working or idle. When either rig is not in use on Meridian-operated wells, the operator may contract it to third parties, or the rig may be idled. The operator has sought other parties to use the rigs and agreed to credit the Company s obligation to some extent, based on revenues from third parties who utilize the rig(s) when the Company is unable to. The rigs were used continuously by the Company through approximately the end of 2008. During the first half of 2009, one rig has been effectively subleased to others at rates less than the dayrate under the Company s contract. The Company is obligated for the difference in dayrates. However, this is the rig owned by the Company and any profits from its use by the operator are shared with the Company. The other rig continued to be utilized drilling a Meridian-operated well through the end of the first quarter of 2009, after which it was released, and is currently under short-term contract to a third party. Expenditures for the rigs when they are not drilling for the Company are included in Rig operations, net on the consolidated statements of operations; see further information regarding these costs in Note 2, Rig operations. Management cannot predict whether utilization of the rigs by third parties will be consistent, nor to what extent it may offset obligations under the dayrate contracts. The Company has not provided any amount for any future losses on these drilling contracts in its financial statements at June 30, 2009.
As noted above, the Company is in discussion with a third party and CIT regarding a forbearance agreement that would grant the third party title to the rig in exchange for release of all accrued and future liabilities under the rig contracts. At June 30, 2009, the rig is included in equipment at a net book value of $5.0 million, accounts payable includes a total of $2.4 million in accrued unpaid invoices from a third party for underutilization of the rig, and accounts receivable includes a total of $645,000 in accrued receivables for the Company s share of profits on the rig. The net total owed to the third party for these items is $1.8 million. Both the rig value and the net payable to the third party would be written off under the terms of the forbearance agreement under discussion.

9. STOCKHOLDER S EQUITY

Common Stock

In March 2007, the Company s Board of Directors authorized a share repurchase program. Under the program, the Company may repurchase in the open market or through privately negotiated transactions up to $5 million worth of common shares per year over three years. The timing, volume, and nature of share repurchases will be at the discretion of management, depending on market conditions, applicable securities laws, and other factors. Prior to implementing this program, the Company was required to seek approval of the repurchase program from the Lenders under the Credit Facility. The repurchase program was approved by the Lenders, subject to certain restrictive covenants. The Lenders in the Credit Facility unanimously approved an amendment increasing the available limit for the Company s repurchase of its common stock from $1.0 million to $5.0 million annually. The amendment contained restrictive covenants on the Company s ability to repurchase its common stock including (i) the Company cannot utilize funds under the Credit Facility to fund any stock repurchases and (ii) immediately prior to any repurchase, availability under the Credit Facility must be equal to at least 20% of the then effective borrowing base. From March 2007, the inception of the share repurchase program, through June 30, 2009, the Company had repurchased 535,416 common shares at a cost of $1,234,000, of which 501,300 shares have been reissued for 401(k) contributions, for contract services and for compensation, and 34,116 have been retired. The program does not require the Company to repurchase any specific number of shares and may be modified, suspended, or terminated at any time without prior notice. The Company did not repurchase any shares during the six months ended June 30, 2009 and does not expect to make share repurchases in the near term.

General Partner Warrants

As of December 31, 2008, the Company had outstanding warrants (the General Partner Warrants) that entitle Joseph A. Reeves, Jr. and Michael J. Mayell to purchase an aggregate of 1,884,544 shares of common stock at an exercise price of $0.10 per share through December 31, 2015. The number of shares of common stock purchasable upon the exercise of each warrant and its corresponding exercise price are subject to various anti-dilution adjustments. Messrs. Reeves and Mayell, respectively, are the former Chief Executive Officer and former Chief Operating Officer of the Company.

In June 2008, the FASB Emerging Issues Task Force issued EITF Abstract Issue No. 07-05, Determining Whether an Instrument (or Embedded Feature) Is Indexed to an Entity s Own Stock (EITF 07-05). The issue clarifies the determination of equity instruments which may qualify for an exemption from SFAS 133, Accounting for Derivative Instruments and Hedging Activities (SFAS 133). Generally, equity instruments which qualify under the guidelines of EITF 07-05 may be accounted for in equity accounts; those which do not qualify are subject to derivative accounting. The Company adopted EITF 07-05 on January 1, 2009. Its provisions were considered in regard to the General Partner Warrants and it was determined that they were not indexed to the Company s own stock. Accordingly, a charge of $960,000 was recorded on January 1, 2009 to retained earnings to reflect the cumulative effect of recording the 1,884,544 warrants at fair value, with an offsetting entry to accrued liabilities. Adjustments to fair value are being made on a prospective basis, beginning in 2009. For the six months and three months ended June 30, 2009, the Company recorded a gain (loss) on the valuation of the warrants of $399,000 and ($241,000), respectively, which is included in General and Administrative Expense.

In addition to customary anti-dilution adjustments, the number of shares of common stock and the exercise price per share of the General Partner Warrants are subject to adjustment for any issuance of common stock by the Company such that each warrant will permit the holder to purchase at the same aggregate exercise price, a number of shares of common stock equal to the percentage of outstanding shares of common stock that the holder could purchase before the issuance. Currently each of these two warrant arrangements permits the holder to purchase approximately 1% of the outstanding shares of the common stock for an aggregate exercise price of $94,303.

At June 30, 2009, 1,872,678 General Partner Warrants were outstanding and included in accrued liabilities at a total fair value of $562,000. Fair value is based on the Black-Scholes model for option pricing.

Other

Other significant changes in stockholders equity include the distribution of shares from treasury as described in Note 10.

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10. CONTRACT SETTLEMENTS AND RABBI TRUST

In April 2008 the Company made significant changes in the structure of the compensation of two executives, Mr. Joseph A. Reeves and Mr. Michael J. Mayell, former Chief Executive Officer and former Chief Operating Officer. Effective April 29, 2008, the employment contracts for Messrs. Reeves and Mayell were replaced with new agreements. In addition, certain other agreements that governed other elements of their compensation packages were also settled. As a result of the agreements, the Company recorded $9.9 million in contract settlement expense in the second quarter of 2008, and placed that amount of cash in a Rabbi Trust for the former officers. In June 2009, pursuant to the contractual terms, the cash was distributed from the trust to the former officers.

In addition, the Company discontinued the deferred compensation plan provided to these officers, which resulted in the issuance of a total of 1,803,291 shares of new common stock for Messrs. Reeves and Mayell (combined) on July 2, 2008. The shares issued were net of a reduction of 1,001,511 shares withheld from issuance in lieu of the former executives personal withholding tax. An additional 1,712,114 new shares (856,057 shares to each of the two former officers) were placed in the Rabbi Trust in the third quarter of 2008, and distributed to the former officers in June 2009. The shares were again issued net of shares withheld for personal withholding tax (a total of 610,938 shares were withheld from distribution and retired). Substantially all of the compensation expense related to these shares was recognized historically, when the rights to such future shares were granted.

Prior to distribution, the cash in the Rabbi Trust was included on the Consolidated Balance Sheets under Restricted Cash, and the shares in the trust were accounted for as treasury shares, assigned a value based on the closing market price on the date they were issued, October 2, 2008. Until distribution, the assets of the trust belonged to the Company, but were effectively restricted due to the obligation to the former officers.

11. EARNINGS PER SHARE

The following table sets forth the computation of basic and diluted net earnings (loss) per share (in thousands, except per share):

	Three Months Ended June 30,	
	2009	**2008**
Numerator:		
Net earnings (loss)	$ (1,462)	$ 839
Denominator:		
Denominator for basic earnings per share weighted-average shares outstanding	92,460	91,387
Effect of potentially dilutive common shares:		
Warrants and stock rights (a)	NA	3,099
Employee and director stock options (a)	NA	15
Denominator for diluted earnings per share weighted-average shares outstanding and assumed conversions	92,460	94,501
Basic earnings (loss) per share	$ (0.02)	$ 0.01
Diluted earnings (loss) per share	$ (0.02)	$ 0.01

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	Six Months Ended June 30, 2009	2008
Numerator:		
Net earnings (loss)	$ (62,423)	$ 4,402
Denominator:		
Denominator for basic earnings per share weighted-average shares outstanding	92,455	90,372
Effect of potentially dilutive common shares:		
Warrants and stock rights (a)	NA	4,521
Employee and director stock options (a)	NA	8
Denominator for diluted earnings per share weighted-average shares outstanding and assumed conversions	92,455	94,901
Basic earnings (loss) per share	$ (0.68)	$ 0.05
Diluted earnings (loss) per share	$ (0.68)	$ 0.05

(a) The number of warrants excluded for the three months and six months ended June 30, 2009 totaled approximately 3.3 million. The number of options excluded for those periods totaled approximately 0.7 million. The number of warrants excluded for the three months and six months ended June 30, 2008 totaled approximately 1.4 million. A total of 3.4 million options were excluded for the three months and six months ended June 30, 2008, because the options exercise price was greater than the average market price of the common shares, which made them anti-dilutive.

Warrants and stock options for which the exercise prices were greater than the average market price of the Company s common stock are excluded from the computation of diluted earnings per share. Stock rights issued under our deferred compensation plan, which had all been converted and were no longer outstanding during the first six months of 2009, had no exercise price and are included in diluted earnings per share for the three months and six months ended June 30, 2008. All potentially dilutive shares, whether from options, warrants, or rights, are excluded when there is an operating loss, because inclusion of such shares would be anti-dilutive.

12. RISK MANAGEMENT ACTIVITIES

Management of Financial Risk

The Company s operating environment includes two primary financial risks which could be addressed through derivatives and similar financial instruments: the risk of movement in oil and natural gas commodity prices, which impacts revenue, and the risk of interest rate movements, which impacts interest expense from floating rate debt.

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The Company currently does not utilize derivative contracts or any other form of hedging against interest rate risk.

The Company utilizes derivative contracts to address the risk of adverse oil and natural gas commodity price fluctuations. While the use of derivative contracts limits the downside risk of adverse price movements, it may also limit future gains from favorable movements. No derivative contracts have been entered into for trading purposes, and the Company has the intent to hold each remaining instrument to maturity. The Company s commodity derivative contracts are considered cash flow hedges under generally accepted accounting principles.

Oil and Natural Gas Hedging Contracts

The Company has historically utilized derivative contracts to hedge the sale of a portion of its future production. The Company s objective is to reduce the impact of commodity price fluctuations on both income and cash flow, as well as to protect future revenues from adverse price movements. Management considers some exposure to market pricing to be desirable, due to the potential for favorable price movements, but prefers to achieve a measure of stability and predictability over revenues and cash flows by hedging some portion of production. The Company s commodity derivative positions as of June 30, 2009 hedge approximately 31% of proved developed natural gas production and 12% of proved developed oil production during the remaining terms of all derivative agreements in the aggregate.

The Company has historically chosen derivative contracts in the form of costless collars. These agreements ensure the Company receives a minimum (floor) price for the commodity, while concurrently limiting the price to a specified maximum (ceiling). Typically, the contracts specify monthly hedged volumes subject to the floor and ceiling prices over a period of 6 to 18 months. The contracts are settled monthly based on the NYMEX futures contract. Counter-parties to these contracts are large financial institutions that are members of the lending group which is party to our Credit Facility. The following table lists all of the Company s commodity derivative contracts as of June 30, 2009:

	Type	Notional Amount	Floor Price ($ per unit)	Ceiling Price ($ per unit)	Estimated Fair Value Asset (Liability) June 30, 2009 (in thousands)
Natural Gas (mmbtu)					
July 2009 Dec 2009	Collar	530,000	$ 7.50	$ 10.45	$ 1,691
July 2009 Dec 2009	Collar	330,000	$ 8.00	$ 10.30	1,205
July 2009 Dec 2009	Collar	230,000	$ 8.00	$ 13.35	842
Total Natural Gas					3,738
Crude Oil (bbls)					
July 2009 Dec 2009	Collar	11,000	$ 70.00	$ 93.55	41
July 2009 Dec 2009	Collar	16,000	$ 80.00	$ 111.00	172
July 2009 Dec 2009	Collar	21,000	$ 85.00	$ 128.50	314
Total Crude Oil					527
					$ 4,265

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See Note 15, however, for information on modifications to these contracts that were made in August, 2009.

Accounting and financial statement presentation for derivatives

The Company accounts for its derivative contracts under the provisions of SFAS 133. Under SFAS 133, the Company s commodity derivatives are designated as cash-flow hedges and are stated at fair value on the Consolidated Balance Sheets. See Note 4, Fair Value Measurements for further information on how fair values of derivative instruments are determined. Changes in the fair value of the contracts, which occur due to commodity price movements, are offset in Other Comprehensive Income. When the derivative contract or a portion of it matures, the gain or loss is settled in cash and reclassified from Accumulated Other Comprehensive Income to Revenues from Oil and Natural Gas. Net settlements under hedging agreements increased (decreased) oil and natural gas revenues by $3,452,000 and ($2,715,000) for the three months ended June 30, 2009 and 2008, respectively and $7,023,000 and ($3,319,000) for the six months ended June 30, 2009 and 2008, respectively. A gain or loss may be recorded to earnings prior to contract maturity if a portion of the cash flow hedge becomes ineffective under the guidelines provided under generally accepted accounting principles, or if the forecasted transaction is no longer expected to occur. Although the Company periodically records gains or losses from hedge ineffectiveness, there have been no losses recorded due to cancellations or changes in expectations regarding occurrence of the hedged transactions. The following two tables provide information regarding assets, liabilities, gains, and losses related to derivative contracts, and where these amounts are reflected within the Company s financial statements (in thousands):

	Fair Values of Derivative Contracts at	
Description and location within Consolidated Balance Sheet	June 30, 2009	December 31, 2008
Derivative contracts designated as hedging instruments Commodities Contracts		
Current assets from price risk management activities	$ 4,284	$ 8,447
Non-current assets from price risk management activities		
Current liabilities from price risk management activities	$ 19	$ 311
Non-current liabilities from price risk management activities		
Derivative contracts not designated as hedging instruments	NONE	NONE

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Effect of Derivative Contracts on the
Consolidated Balance Sheets and the Consolidated Statements of Operations

Description	Location of Gain (Loss) within Financial Statements	For the three months ended June 30, 2009	June 30, 2008	For the six months ended June 30, 2009	June 30, 2008
Derivative contracts designated as cash flow hedging instruments:					
Gain (loss) on derivative contracts recognized in Other Comprehensive Income (OCI)					
Commodities Contracts	Accumulated Other Comprehensive Income	(642)	(18,125)	3,156	(24,423)
Gain (loss) on derivative contracts reclassified from OCI to earnings					
Commodities Contracts	Oil and Natural Gas Revenues	3,452	(2,715)	7,023	(3,319)
Gain (loss) due to hedging ineffectiveness reported in earnings					
Commodities Contracts	Revenues from Price Risk Management Activities	(5)	4	(3)	(30)
Fair value of derivative contracts designated as cash flow hedging instruments, excluded from effectiveness assessments		NONE	NONE	NONE	NONE
Derivative contracts not designated as hedging instruments		NONE	NONE	NONE	NONE

As of June 30, 2009, the Company had an unrealized gain of $4.3 million (pre-tax and net of tax) deferred in Accumulated Other Comprehensive Income. Based upon oil and natural gas commodity prices at June 30, 2009, all of the unrealized gain deferred in Accumulated Other Comprehensive Income could potentially increase gross revenues in the next six months. These derivative agreements expire December 31, 2009.

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Special terms in derivative contracts

Although the Company s counterparties provide no collateral, the master derivative agreements with each counterparty effectively allow the Company, at its option, so long as it is not a defaulting party, after a default or the occurrence of a termination event, to set-off an unpaid hedging agreement receivable against the interest of the counterparty in any outstanding balance under the Credit Facility. In practice, no such set-off has been made, and all settlements have been made in cash. As of December 31, 2008, the Company was in covenant default, and continuing at June 30, 2009, the Company is in payment and covenant default under the Credit Facility, the breach of which is also a cross-default under the master derivative agreements. Although the Company s hedge counterparties have continued to make contract payments subsequent to the default, they are not obligated to make payments to the Company under the hedging agreements while the Company s default is continuing. The Company s set-off rights under the master derivative agreements cannot be exercised due to such default. The Company s hedging counterparties may exercise their remedies under the hedging agreements, and potentially under the Credit Facility, on account of the Company s default, which includes a right to terminate the agreements and set-off any settlement amount due to the Company against amounts owed under the Credit Facility. The settlement amount would be based on the estimated value of the remaining forward portion of the contracts based on market values at settlement.

If a counterparty were to default in payment of an obligation under the master derivative agreements, the Company would be exposed to commodity price fluctuations, and the protection intended by the hedge would be lost. The value of assets from price risk management would be impacted. In addition, as expected cash flows from hedging contracts are included in computing future net revenues, the ceiling test could be impacted, which could result in a non-cash write-down of oil and natural gas properties.

13. SHARE-BASED COMPENSATION

Stock Options

The Company records share-based compensation expense based on the fair value of the share-based award determined at grant date and recognized over the service period, which is generally the vesting period of the award. Share-based compensation expense of approximately $44,000 and $96,000 was recorded for the three months and six months ended June 30, 2009, respectively, and $711,000 and $1,324,000 was recorded for the three months and six months ended June 30, 2008, respectively. Compensation paid in share-based awards included stock options and non-vested shares granted to our employees and directors and stock rights awarded under our deferred compensation plan for certain executives, which was discontinued after April 2008.

14. ASSET RETIREMENT OBLIGATIONS

The Company estimates the present value of future costs of dismantlement and abandonment of its wells, facilities, and other tangible long-lived assets, recording them as liabilities in the period incurred. Asset retirement obligations are calculated using an expected present value technique. Salvage values are excluded from the estimation.

When the liability is initially recorded, the entity increases the carrying amount of the related long-lived asset. Accretion of the liability is recognized each period, and the capitalized cost is amortized over the

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useful life of the related asset. Upon settlement of the liability, the Company incurs a gain or loss based upon the difference between the estimated and final liability amounts. The Company records gains or losses from settlements as adjustments to the full cost pool.

The following table describes the change in the Company s asset retirement obligations for the six months ended June 30, 2009 (thousands of dollars):

Asset retirement obligation at December 31, 2008	$ 22,225
Additional retirement obligations recorded in 2009	47
Settlements during 2009	(81)
Revisions to estimates and other changes during 2009	(1,008)
Accretion expense for 2009	1,077
Asset retirement obligation at June 30, 2009	22,260
Less: current portion	599
Asset retirement, long-term, at June 30, 2009	$ 21,661

The Company s revisions to estimates represent changes to the expected amount and timing of payments to settle the asset retirement obligations. These changes primarily result from obtaining new information about the timing of our obligations to plug the natural gas and oil wells and costs to do so.

15. SUBSEQUENT EVENTS

On August 6, 2009, the Company modified all five of its hedging contracts with an affiliate of Fortis Capital Corp. All of the contracts were originally established as oil and natural gas collars. These agreements ensure the Company receives a minimum (floor) price for the commodity, while concurrently limiting the price to a specified maximum (ceiling). Originally, the contracts specified monthly hedged volumes subject to the floor and ceiling prices over a period of 6 to 18 months; all of the modified contracts terminate in December 2009. Each series of obligations, a specified monthly volume at a specified floor and ceiling price, for a term of months, is known as a strip.

At the counterparty s request, the Company agreed to pay $35,000 to eliminate the ceiling portion of the collar agreements for the remainder of the term under each contract with the Fortis affiliate. The floor portion of the collar remains in place. The price was based on NYMEX prices for oil and oil futures on August 6, 2009, and will be settled by exchange of a portion of one floor contract. The Company will reduce the volume under one September floor contract by 10,000 Mmbtu; thus it will be a cashless exchange. The transaction reduces the Company s exposure in case of a precipitous increase in oil and / or natural gas prices during the remaining term of the collars. All five of the modified strips carry floor prices which are substantially above current market prices for oil and natural gas. The value of the 10,000 Mmbtu September floor contract was estimated to be an even exchange for the reduction in the Company s potential obligations under the ceiling portion of the strips, which the counterparty estimated at $35,000.

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

Operations Update

Production volumes for the second quarter of 2009 totaled 3.4 billion cubic feet of gas equivalent (Bcfe), or an average of 37.9 million cubic feet of natural gas equivalent per day (Mmcfe/d) compared to 3.6 Bcfe or 40.1 Mmcfe per day for the second quarter of 2008. Second quarter 2009

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average production of 37.9 Mmcfe/d is up slightly compared to the average daily production of 37.1 Mmcfe/d in the first quarter of 2009. Meridian has been able to maintain a relatively even level of production for the past several quarters despite the fact that capital spending for revenue generating projects was greatly reduced in the first and second quarters of 2009. Capital expenditures for the first six months of 2009 were $12 million compared to $63 million for the first six months of 2008. Although Meridian continues to spend some capital for plugging some older wells, as required by state and lease obligations, the decrease in capital expenditures between the periods was due to the significant reduction in drilling projects. Currently, the overall average daily production for the Company ranges between 34 and 36 Mmcfe/d.

Capital Expenditure Plans for 2009

The Company anticipates the remaining 2009 capital spending budget will be primarily used for required abandonment of existing wells and facilities. We anticipate that the budget will be significantly lower than in past years, reflecting our expectations of reduced cash flows due to commodity price declines and the loss of availability of funds under the Credit Facility. These factors will significantly impact funds available for capital spending. We currently anticipate funding capital expenditures for the remainder of 2009 by utilizing cash flow from operations and cash on hand, augmented by proceeds from sales of assets as possible.

Other Conditions

Industry and Economic 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, 2009, was $55.09 per barrel compared to $98.96 per barrel for the three months ended June 30, 2008, and $45.62 per barrel for the three months ended March 31, 2009. Our average natural gas price (after adjustments for hedging activities) for the three months ended June 30, 2009, was $4.85 per Mcf compared to $11.09 per Mcf for the three months ended June 30, 2008, and $6.07 per Mcf for the three months ended March 31, 2009.

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 impacts our revenues, profitability and ability to maintain or increase our exploration and development program. Pricing also significantly impacts our future net revenue from oil and natural gas, which impacts the ceiling test and related impairment expense. Refer to Item 3, Quantitative and Qualitative Disclosures about Market Risk, for information regarding commodity price risk management activities utilized to mitigate a portion of the near term effects of this exposure to price volatility.

Global capital markets have experienced significant disruptions in the past year, resulting in the closing or restructuring of numerous large financial institutions. Extreme uncertainty about creditworthiness, liquidity and interest rates, as well as the global economic recession, continue to limit credit availability. In addition, the market value of the Company s reserves has decreased, both in the fourth quarter of 2008 and in the first quarter of 2009, though a partial recovery of prices occurred in the second quarter of 2009, due primarily to energy price fluctuations. Our access to credit has significantly declined.

The decrease in oil and natural gas prices has also caused operating cash flows to decline across the industry and at Meridian.

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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, 2008, for further discussion.

The Company adopted Emerging Issues Task Force 07-05 effective January 1, 2009. The adoption requires us to value certain outstanding warrants for our common stock, known as the General Partner Warrants, at fair value at each reporting date. As the fair value changes, the difference from period to period is recognized in the consolidated statement of operations. The fair value is based on the Black-Scholes model for option pricing, and varies from period to period primarily due to fluctuation in the market price of our common stock. Upon adoption, we recorded a charge of $960,000 to retained earnings to reflect the cumulative effect of recording the 1.9 million warrants at fair value on January 1, 2009, with an offsetting entry to accrued liabilities. For the six months ended June 30, 2009, we recorded a reduction of general and administrative expense of $399,000 due to the change in fair value of the warrants; for the three months ended June 30, 2009 the revaluation of the warrants increased expense by $241,000. The factors that determine the fair value are not in our control and may potentially produce a more material impact on future consolidated statements of operations.

Results of Operations

Three Months Ended June 30, 2009 Compared to Three Months Ended June 30, 2008

Operating Revenues. Second quarter 2009 oil and natural gas revenues, which include oil and natural gas hedging activities (see Note 12 of Notes to Consolidated Financial Statements), decreased $23.8 million (51%) as compared to second quarter 2008 revenues due to a 6% decrease in production volumes and a 48% decrease in average commodity prices on a natural gas equivalent basis. Oil and natural gas production volumes totaled 3,444 Mmcfe for the second quarter of 2009 compared to 3,645 Mmcfe for the comparable period of 2008. Our average daily production decreased from 40.1 Mmcfe during the second quarter of 2008 to 37.9 Mmcfe for the second quarter of 2009. Second quarter 2009 production was generally lower due to natural production declines.

The following table summarizes the Company s operating revenues, production volumes and average sales prices for the three months ended June 30, 2009 and 2008:

	Three Months Ended June 30, 2009	2008	Increase (Decrease)
Production Volumes:			
Oil (Mbbl)	231	188	23%
Natural gas (MMcf)	2,058	2,516	(18%)
Mmcfe	3,444	3,645	(6%)
Average Sales Prices:			
Oil (per Bbl)	$ 55.09	$ 98.96	(44%)
Natural gas (per Mcf)	$ 4.85	$ 11.09	(56%)
Mmcfe	$ 6.59	$ 12.77	(48%)
Operating Revenues (000 s):			
Oil	$ 12,723	$ 18,622	(32%)
Natural gas	9,987	27,912	(64%)
Total Operating Revenues	$ 22,710	$ 46,534	(51%)

Operating Expenses. Oil and natural gas operating expenses on an aggregate basis decreased $2.5 million (35%) to $4.6 million during the second quarter of 2009, compared to $7.2 million in the second quarter of 2008. On a unit basis, lease operating expenses decreased $0.62 per Mcfe to $1.34 per Mcfe for the second quarter of 2009 from $1.96 per Mcfe for the second quarter of 2008. Oil and natural gas operating expenses decreased primarily due to decreased compressor, salt water disposal, and fuel costs, lower insurance costs, reduced production, and cost saving measures implemented in the field.

Severance and Ad Valorem Taxes. Severance and ad valorem taxes decreased $1.0 million (34%) to $2.0 million for the second quarter of 2009, compared to $3.0 million during the same period in 2008 primarily because of the decrease in production and to a decrease in taxes per Mcfe. On an equivalent unit of production basis, severance and ad valorem taxes decreased to $0.58 per Mcfe from $0.82 per Mcfe for the comparable three-month period. This unit decrease is primarily related to the decrease in oil and natural gas prices.

Depletion and Depreciation. Depletion and depreciation expense decreased $8.5 million (48%) during the second quarter of 2009 to $9.4 million, from $17.9 million for the same period of 2008. This was the result of lower depreciation expense per unit, combined with a decrease in oil and natural gas production. On a unit basis, depletion and depreciation expense decreased by $2.19 per Mcfe, to $2.72 per Mcfe for the three months ended June 30, 2009, compared to $4.91 per Mcfe for the same period in 2008. The reduction in expense per unit is due to the decrease in the carrying value of oil and gas properties which resulted from the significant impairment write-downs to the properties recorded in December 2008 and March 2009.

***General and Administrative Expense*.** General and administrative expense was $4.3 million in the second quarter of 2009 compared to $5.2 million in the second quarter of 2008. The $0.9 million decrease was primarily due to reductions in staff, largely offset by the discontinuation of capitalized general and administrative expense in the second quarter of 2009. The Company has significantly reduced its capital spending program and as a result a portion of the Company s personnel expenses are no longer capitalized. On an equivalent unit of production basis, general and administrative expenses decreased $0.19 per Mcfe to $1.24 per Mcfe for the second quarter of 2009 compared to $1.43 per Mcfe for the comparable 2008 period primarily due to the Company s staff reductions, largely offset by lower capitalized general and administrative expense. Lower production rates between the periods also partially offset the impact of the expense reductions on a unit basis.

Rig Operations, Net. Rig operations, net is the expense related to underutilized contracted drilling rigs. The Company has drilling contracts covering two rigs which it was unable to utilize for drilling, beginning in the first quarter of 2009 for one rig and in the second quarter of 2009 for the other. Under these drilling contracts the Company is obligated for the daily rate of the rigs regardless of the Company s actual use of the rigs; in practice, the rigs have been utilized by third parties and the Company has recorded a liability for the difference between its contracted dayrate and that collected by the drilling operator from the third party. See further information in Note 2 of Notes to Consolidated Financial Statements. Total net expense related to this underutilization of contracted rigs was $1.8 million in the second quarter of 2009; there was no corresponding expense in the second quarter of 2008.

Contract Settlement Expense. Contract settlement expense of $9.9 million was recorded in the second quarter of 2008 when the employment contracts of certain executive officers were renegotiated. See further information in Note 10 of Notes to Consolidated Financial Statements. Restricted cash decreased $9.9 million in June 2009 when the obligation was discharged by distributing funds from a rabbi trust account.

***Interest Expense*.** Interest expense increased $0.1 million (9%), to $1.5 million for the second quarter of 2009 in comparison to $1.4 million for the second quarter of 2008. The increase is primarily a result of higher average debt balances.

Taxes on Income. Income tax expense for the second quarter of 2009 was zero, compared to $0.8 million in the second quarter of 2008. The elimination of tax benefit from losses originated in the fourth quarter of 2008 as a result of the Company s deferred tax asset valuation allowance. Management believes, given the Company s overall current financial position, that there are significant uncertainties regarding its ability to generate net profits in the near term; thus a tax asset valuation allowance sufficient to offset all deferred tax assets has been continuously maintained since December 2008.

Six Months Ended June 30, 2009 Compared to Six Months Ended June 30, 2008

Operating Revenues. Oil and natural gas revenues during the six months ended June 30, 2009, which include oil and natural gas hedging activities (see Note 12 of Notes to Consolidated Financial Statements) decreased $40.2 million (47%) as compared to first half 2008 revenues due to a 43% decrease in average sale prices on a natural gas equivalent basis, as well as an 8% decrease in production volumes. Our average daily production decreased from 40.5 Mmcfe during the first six months of 2008 to 37.5 Mmcfe for the first six months of 2009. Oil and natural gas production volume totaled 6,784 Mmcfe for the first six months of 2009, compared to 7,376 Mmcfe for the comparable period of 2008. The variance in production volumes between the two periods is primarily due to natural production declines.

The following table summarizes the Company s operating revenues, production volumes and average sales prices for the six months ended June 30, 2009 and 2008:

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	Six Months Ended June 30, 2009	2008	Increase (Decrease)
Production Volumes:			
Oil (Mbbl)	430	372	16%
Natural gas (MMcf)	4,205	5,142	(18%)
Mmcfe	6,784	7,376	(8%)
Average Sales Prices:			
Oil (per Bbl)	$ 50.71	$ 93.00	(45%)
Natural gas (per Mcf)	$ 5.48	$ 9.79	(44%)
Mmcfe	$ 6.61	$ 11.52	(43%)
Operating Revenues (000 s):			
Oil	$ 21,794	$ 34,628	(37%)
Natural gas	23,025	50,354	(54%)
Total Operating Revenues	$ 44,819	$ 84,982	(47%)

Operating Expenses. Oil and natural gas operating expenses on an aggregate basis decreased $4.0 million (30%) to $9.2 million during the first six months of 2009, compared to $13.2 million in 2008. Expenses decreased primarily due to compressor, salt water disposal, and fuel costs, lower insurance costs, reduced production, and cost saving measures implemented in the field. On a unit basis, lease operating expenses decreased $0.43 per Mcfe to $1.36 per Mcfe for the first six months of 2009 from $1.79 per Mcfe for the first half of 2008. The decrease in the per Mcfe rate is due to the reduction in expenses.

Severance and Ad Valorem Taxes. Severance and ad valorem taxes decreased $2.0 million (35%), to $3.6 million for the first six months of 2009 in comparison to the same period in 2008, primarily because of the decrease in prices. On an equivalent unit of production basis, severance and ad valorem taxes decreased to $0.53 per Mcfe from $0.76 per Mcfe for the comparable six-month period.

Depletion and Depreciation. Depletion and depreciation expense decreased $14.5 million (41%) during the first half of 2009 to $21.1 million, from $35.6 million for the same period of 2008. This was primarily the result of the decline in the depletion rate as compared to the 2008 period. The reduction in the rate is due to the decrease in the carrying value of oil and gas properties which resulted from the significant impairment write-downs to the properties recorded in December 2008 and March 2009. On a unit basis, depletion and depreciation expense decreased by $1.71 per Mcfe, to $3.12 per Mcfe for the six months ended June 30, 2009, compared to $4.83 per Mcfe for the same period in 2008.

General and Administrative Expense. General and administrative expense was $7.7 million for the first six months of 2009 and for the same period in 2008 was $9.3 million. This decrease was primarily due to reductions in staff, largely offset by the discontinuation of capitalized general and administrative expense in the second quarter of 2009. The Company has significantly reduced its capital spending program and as a result a portion of the Company s personnel expenses are no longer capitalized. On an equivalent unit of production basis, general and administrative expenses decreased $0.13 per Mcfe to $1.13 per Mcfe for the first six months of 2009 compared to $1.26 per Mcfe for the comparable 2008 period.

Rig Operations, Net. Rig operations, net is the expense related to underutilized contracted drilling rigs. The Company has drilling contracts covering two rigs which it was unable to utilize for drilling, beginning in the first quarter of 2009 for one rig and in the second quarter of 2009 for the other. Under

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these drilling contracts the Company is obligated for the daily rate of the rigs regardless of the Company s actual use of the rigs; in practice, the rigs have been utilized by third parties and the Company has recorded a liability for the difference between its contracted dayrate and that collected by the drilling operator from the third party. See further information in Note 2 of Notes to Consolidated Financial Statements. Total net expense related to this underutilization of contracted rigs was $1.8 million in the first half of 2009; there was no corresponding expense in the first half of 2008.

Contract Settlement Expense. Contract settlement expense of $9.9 million was recorded in the second quarter of 2008 when the employment contracts of certain executive officers were renegotiated. See further information in Note 10 of Notes to Consolidated Financial Statements. Restricted cash decreased $9.9 million in June 2009 when the obligation was discharged by distributing funds from a rabbi trust account.

Impairment of Long-Lived Assets. A decline in oil and natural gas prices as of March 31, 2009, resulted in the Company recognizing a non-cash impairment totaling $59.5 million of its oil and natural gas properties under the full cost method of accounting in the first half of 2009. There was no corresponding item in the first half of 2008.

Interest Expense. Interest expense increased $0.6 million (24%), to $3.1 million for the first six months of 2009 in comparison to the first half of 2008. The increase is primarily a result of higher debt balances, partially offset by decreased interest rates.

Liquidity and Capital Resources

Cash Flows. Net cash provided by operating activities was $9.5 million for the six months ended June 30, 2009, as compared to $45.7 million for the same period in 2008. The decrease of $36.2 million was primarily due to lower crude oil and natural gas prices and lower natural gas production volumes, which reduced revenues by $40.2 million. The impact of the revenue decrease was somewhat mitigated by a total of $7.6 million in reduced non-discretionary expenses for lease operations, severance and ad valorem taxes, and general and administrative expenses. However, operating cash flow was impacted negatively by changes in working capital accounts unrelated to debt totaling $9.9 million. The cash outflow from these working capital accounts primarily reflects the paydown during the first half of 2009 of obligations to vendors and joint interest partners as we decrease our drilling and other capital expenditures, establishing a lower base of payables related to operations. Other working capital changes included paydown of our retention bonus obligation to our employees (a non-recurring item), which was $2.0 million at the beginning of the year, and a reduction in payables to royalty owners of $1.5 million due to declines in commodities prices. Our trade receivables provided $4.4 million in funds, as that balance also moved to a lower base due to decreased revenues. We anticipate that our cash from operations will continue to be impacted by volatility in the prices of crude oil and natural gas.

Net cash used in investing activities was $17.4 million during the six months ended June 30, 2009, versus $68.2 million in the first six months of 2008 due to decreased capital expenditures. In the first half of 2009, we participated in drilling only two wells, after which we have confined our activities to required abandonment of existing wells and facilities. We expect to continue with the approach of reduced capital expenditures, funded by cash from operations and asset sales, for the remainder of 2009. This is necessitated by the loss of availability of credit and amounts currently owed under our credit facility.

Cash flows used in financing activities during the first six months of 2009 were $1.7 million, compared to cash provided by financing activities of $25.5 million during the first six months of 2008 primarily due to the net drawdown on the credit facility of $10 million in the first quarter of 2008, plus the new debt incurred under the rig note in the second quarter of 2008.

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Outlook. As further described below under Credit Facility, the Company s borrowing base was redetermined by our bank group earlier this year. Fortis Capital Corp., the administrative agent for the bank group, notified the Company that its borrowing base had been reduced from $95 million to $60 million, resulting in a borrowing base deficiency of $34.5 million. The borrowing base was lowered due primarily to the reduction in borrowing capacity attributable to the value of Meridian s oil and gas properties as a result of precipitous declines in commodity prices. Under the terms of the current credit facility agreement, the Company had 90 days from the April 30, 2009 effective date of the redetermination to cure the borrowing base deficiency. Accordingly, a $34.5 million payment to our bank group for the borrowing base deficiency was due July 29, 2009. The Company does not currently have sufficient cash available to repay the deficiency and, consequently, we failed to pay such amount when due and are in default under the credit facility for such failure. Meridian is currently in discussions with the lenders regarding the deficiency and default. These discussions deal with providing additional security, obtaining waivers on other covenant-based events of default (see below), and on a forbearance agreement that would allow Meridian more time to execute potential solutions for the deficiency. The amount outstanding under the credit facility is $94.5 million at June 30, 2009 and August 10, 2009.

Our default under the credit facility resulted in a cross-default under certain commodities hedging agreements with two members of the lending group under the credit facility. Default remedies available to the counterparties under the terms of the hedging agreements include settling the remaining forward portion of the contracts based on market values at settlement, and the right to set-off any settlement amount due to the Company against amounts owed under the credit facility. The contracts are carried as $4.3 million assets from price risk management in the accompanying balance sheet as of June 30, 2009. The contracts were somewhat modified on August 6, 2009; see Note 15 in the accompanying Notes to Consolidated Financial Statements.

In addition, our default under the credit facility resulted in a cross-default under our $8.0 million loan secured in 2008 for the purchase of a drilling rig (see further information below under Rig Note). Default remedies available to the lender include acceleration of all payment of principal and interest. We are also in discussions with that lender, who is considering forbearance under various terms, described below.

No assurance can be provided that the lenders will agree to any forbearance or other arrangements that would allow Meridian more time to execute potential solutions for the deficiencies.

We are pursuing other options for repayment of our indebtedness, including the sale of strategic and nonstrategic assets or obtaining capital from other sources. However, due to the default under the credit facility, we have increased the amount of our oil and natural gas properties provided as security under that agreement to not less than 95% of the value of these assets. We may not be able to sell assets on terms that we consider advantageous to us and our shareholders, and capital on acceptable terms may not be available from other sources. If we are unable to obtain concessions from the lenders under the two credit agreements and our counterparties under the hedging agreements, and comply with the terms of any forbearance or other agreements, we would continue to be in default under the credit facility, the rig note and the hedging agreements. We would be subject to the exercise of remedies by such parties on account of such defaults. The exercise of such remedies could potentially result in us seeking protection under federal bankruptcy laws. Such relief could materially and adversely affect the Company and its shareholders.

Because of the defaults under the credit facility and the rig note, all balances owing under those agreements have been classified as current liabilities in the accompanying balance sheet as of June 30, 2009, resulting in a negative working capital balance of $105.9 million. Excluding acceleration of the two loans, working capital is negative $5.3 million.

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Continuing Obligations. In addition to the amounts due under our credit facility and rig note, the Company has continuing obligations under various contracts, the most significant of which are the two drilling contracts described in Notes 2 and 8 of the accompanying Notes to Consolidated Financial Statements. Under these contracts, we will continue to be obligated to pay daily rig rates for two drilling rigs regardless of whether we are able to use the rigs or they are idle. This obligation has, in the first half of 2009, been mitigated by third party use of the rigs, but we remain liable to the rig operator for any shortfall in rig rate from our contracted rate. Net expense related to underutilization of the rigs is $1.8 million for the first half of 2009. The contracts terminate in February and March of 2010. The Company is working with the rig operator to gain release from these contractual obligations as described below, Rig Note.

For a more complete list of contractual obligations, refer to our 2008 Form 10-K, Item 7, Liquidity and Capital Resources, Cash Obligations.

Credit Facility. On December 23, 2004, the Company amended its credit facility to provide for a four-year $200 million senior secured credit facility (the Credit Facility) with Fortis Capital Corp., as administrative agent, sole lead arranger and bookrunner; Comerica Bank as syndication agent; and Union Bank of California as documentation agent. Bank of Nova Scotia, Allied Irish Banks PLC, RZB Finance LLC and Standards Bank PLC completed the syndication group.

On February 21, 2008, the Company amended the Credit Facility. The lending institutions under the amended Credit Facility include Fortis Capital Corp. as administrative agent, co-lead arranger and bookrunner; The Bank of Nova Scotia, as co-lead arranger and syndication agent; Comerica Bank, US Bank NA and Allied Irish Bank plc each in their respective capacities as lenders (collectively, the Lenders.) The maturity date was extended to February 21, 2012, and the borrowing base was redetermined to be $110 million. Interest rates were slightly increased by increasing the range of the add-on to the prime base rate by 25 basis points on the lower end of the range and by 50 basis points on the higher end of the range; the range of the add-on to the alternative base rate was increased by 25 basis points on the higher end of the range.

On December 19, 2008, the Company entered into the Second Amendment to Credit Agreement to the Credit Facility (Second Amendment). The Second Amendment redetermined the borrowing base at $95 million, limiting borrowing to the amount outstanding at December 31, 2008. In addition, interest rates were increased by increasing the range of the add-on to the prime base rate by 50 basis points on the lower end of the range and by 75 basis points on the higher end of the range; the range of the add-on to the alternative base rate was increased by the same amounts.

The Credit Facility is subject to semi-annual borrowing base redeterminations on April 30 and October 31 of each year. In addition to the scheduled semi-annual borrowing base redeterminations, the Lenders or the Company have the right to redetermine the borrowing base at any time, provided that no party can request more than one such redetermination between the regularly scheduled borrowing base redeterminations. The determination of the borrowing base is subject to a number of factors, including quantities of proved oil and natural gas reserves, the banks price assumptions and other various factors unique to each member bank. The Lenders can redetermine the borrowing base to a lower level than the current borrowing base if they determine that the Company s oil and natural gas reserves, at the time of redetermination, are inadequate to support the borrowing base then in effect. In the event the redetermined borrowing base is less than outstanding borrowings under the Credit Facility, the Company will be required to repay the deficit within a 90-day period.

On April 13, 2009, the Lenders notified the Company that, effective April 30, 2009, the borrowing base was reduced from its then-current and fully drawn $95 million to $60 million. The Credit Facility provides that outstanding borrowings in excess of the borrowing base must be repaid within 90 days after the redetermination. Accordingly, a $34.5 million payment to the Lenders for the borrowing base deficiency was due July 29, 2009. The Company does not currently have sufficient cash available to repay the deficiency and, consequently, failed to pay such amount when due and is in default under the Credit Facility for such failure.

The terms of the Credit Facility contain numerous covenants and restrictions. Currently, the Company is also in default of certain covenants, including one that requires that the Company maintain a current ratio (as defined in the Credit Facility) of at least one to one. The current ratio, as defined, was less than the required one to one at December 31, 2008, March 31, 2009 and June 30, 2009. The Company is also in default of the requirement that the Company s auditors opinion for the current financial statements be without modification. The Company s 2008 audit report from its independent registered accounting firm included a going concern explanatory paragraph that expressed substantial doubt about the Company s ability to continue as a going concern. As a result of the defaults, the outstanding Credit Facility balance of $95 million at December 31, 2008 and $94.5 million at June 30, 2009 has been classified in current liabilities on the accompanying consolidated balance sheets.

Under the terms of the Credit Facility, the Lenders have various remedies available in the event of a default, including acceleration of payment of all principal and interest. The Company is currently in discussions with the Lenders regarding entering into a forbearance agreement pursuant to which such parties would forbear for an agreed period of time from exercising remedies otherwise available to them as a result of the Company s covenant and payment defaults. No assurance can be provided that the Lenders will agree to any such arrangements.

Obligations under the Credit Facility are secured by pledges of outstanding capital stock of the Company s subsidiaries and by a first priority lien on not less than 75% (95% in the case of an event of default) of its present value of proved oil and natural gas properties. In addition, the Company is required to deliver to the Lenders and maintain satisfactory title opinions covering not less than 70% of the present value of proved oil and natural gas properties. Because of the defaults, in accordance with the Credit Facility, we have granted mortgages on certain of our producing properties that increase from not less than 75% to not less than 95% the amount of the present value of our proved oil and natural gas properties that are secured by pledges to our Lenders. The Credit Facility also contains other restrictive covenants, including, among other items, maintenance of certain financial ratios, restrictions on cash dividends on common stock and under certain circumstances preferred stock, limitations on the redemption of preferred stock, limitations on repurchases of common stock, restrictions on incurrence of additional debt, and an unqualified audit report on the Company s consolidated financial statements. As noted above, at December 31, 2008 and June 30, 2009, the Company was in default of certain of these covenants, as well as the payment default by failure to repay principal after the reduction of the borrowing base.

Under the Credit Facility, the Company may secure either (i) (a) an alternative base rate loan that bears interest at a rate per annum equal to the greater of the administrative agent s prime rate; or (b) federal funds-based rate plus 1/2 of 1%, plus an additional 1.25% to 2.50% depending on the ratio of the aggregate outstanding loans and letters of credit to the borrowing base 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 2.0% to 3.25%, depending on the ratio of the aggregate outstanding loans and letters of credit to the borrowing base. At December 31, 2008, the three-month LIBOR interest rate was 1.425%; at June 30, 2009 it was 0.6%, and the prime rate remained at 3.25%. During the first quarter of 2009, the Lenders informed the Company that all outstanding tranches of debt would be converted to prime-based from LIBOR-based upon maturity. The Credit Facility continues to provide for commitment fees of 0.375% calculated on the difference between the borrowing base and the aggregate outstanding loans and letters of credit under the agreements. As of July 1, 2009, outstanding borrowing under the Credit Facility totaled $94.5 million.

Rig Note. On May 2, 2008, the Company, through its wholly owned subsidiary TMR Drilling Corporation (TMRD), entered into a financing agreement with The CIT Group/Equipment Financing, Inc. (CIT). Under the terms of the agreement, TMRD borrowed $10.0 million, at a fixed interest rate of 6.625%, in order to refinance the purchase of a land-based drilling rig to be used in Company operations. The rig had been purchased using cash on hand and funds available to the Company under the Credit Facility. Funds from the new agreement were used to reduce borrowing under the Credit Facility. The loan is collateralized by the drilling rig, as well as general corporate credit. The term of the loan is five years; monthly payments of $196,248 for interest and principal are to be made until the loan is completely repaid at termination of the agreement on May 2, 2013.

Effective as of December 31, 2008, the Company s defaults under the Credit Facility also resulted in a cross-default under the rig note. The remedies available to CIT in the event of default include acceleration of all principal and interest payments. Accordingly, all indebtedness under the rig note, $8.8 million at December 31, 2008 and $8.0 million at June 30, 2009, has been classified in current liabilities on the accompanying consolidated balance sheets.

The Company is in discussions with CIT regarding a forbearance agreement under which CIT would forbear to exercise its default remedies for a specified period of time. The current proposal anticipates that, as a condition to the forbearance, the secured drilling rig would be transferred to a third party, with the third party providing a guarantee of the Company s payment obligations to CIT. There can be no assurance of the outcome of these discussions with CIT or any third party.

The third party under consideration is the party to whom the Company is obligated under certain drilling contracts. The Company would obtain release of those obligations under the forbearance agreement in discussion with CIT, in exchange for transfer of the rig.

Oil and Natural Gas Hedging Activities. The Company may address market risk by selecting instruments with fluctuating values that correlate strongly with the underlying commodity being hedged. From time to time we may enter into derivative contracts to hedge the price risks associated with a portion of anticipated future oil and natural gas production. These contracts allow the Company to predict with greater certainty the effective oil and natural gas prices to be received for our hedged 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.

These hedging contracts have been designated as cash flow hedges under generally accepted accounting principles 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; see Note 12 contained elsewhere in this report. All other changes in fair value are reported in the statement of comprehensive loss as unrealized gains or losses from hedging activities.

Capital Expenditures. Total capital expenditures for the first half of 2009 were approximately $12.2 million. Drilling in the first quarter included two wells, both spudded near the end of the fourth quarter of 2008 in the Austin Chalk play, one operated and one non-operated. There were no wells spudded during the second quarter of 2009. Capital expenditures for subsequent quarters will depend on the availability of capital.

The Company anticipates that remaining 2009 capital spending will be primarily used for required abandonment of existing wells and facilities. Expenditures will be significantly lower than in past years, reflecting reduced cash flows due to commodity price declines and the loss of availability of funds under the Credit Facility. These factors will continue to significantly impact funds available for capital spending. We currently anticipate funding the remainder of 2009 capital expenditures by utilizing cash flow from operations and cash on hand, augmented by proceeds from sales of assets as possible.

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.

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. 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.

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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 available data and of engineering and geological interpretation and judgment. Reserve estimates may be 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. 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.

Full-Cost Ceiling Test. At the end of each quarter, the unamortized cost of oil and natural gas properties, net of related deferred income taxes, is limited to the sum of the estimated future after-tax net revenues from proved properties using period-end prices, after giving effect to cash flow hedge positions, discounted at 10%, and the lower of cost or fair value of unproved properties adjusted for related income tax effects.

The calculation of the ceiling test and the depletion expense are based on estimates of proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production, timing, and plan of development. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing, and production subsequent to the date of the estimate may justify a revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

At March 31, 2009, the unamortized cost of our oil and natural gas properties, net of related deferred income taxes, exceeded the ceiling under the full cost method of accounting for oil and natural gas properties. Accordingly, based on March 31, 2009 pricing of $3.76 per Mcf of natural gas and $49.66 per barrel of oil, in the first quarter of 2009, the Company recognized a non-cash impairment of $59.5 million of the Company s oil and natural gas properties under the full cost method of accounting. A non-cash impairment of $216.8 million ($203.2 million after tax) was recognized in the fourth quarter of 2008, based on prices prevailing at the time.

Due to the imprecision in estimating oil and natural gas revenues as well as the potential volatility in oil and natural gas prices and their effect on the carrying value of our proved oil and natural gas reserves, there can be no assurance that write-downs in the future will not be required as a result of factors that may negatively affect the present value of proved oil and natural gas reserves and the carrying value of oil and natural gas properties, including volatile oil and natural gas prices, downward revisions in estimated proved oil and natural gas reserve quantities and unsuccessful drilling activities.

At June 30, 2009, the Company had a cushion (i.e., the excess of the ceiling over capitalized costs) of approximately $30.4 million (pretax and after-tax). A 10% increase in prices would have increased the cushion by approximately 92%. A 10% decrease in prices would have decreased the cushion by approximately 91%. Decreases in prices affecting the end of subsequent accounting periods, net of the effect of the Company s hedging positions, may necessitate additional impairment charges. Any future impairment would be impacted by changes in the accumulated costs of oil and natural gas properties, which may in turn be affected by sales or acquisitions of properties and additional capital expenditures. Future impairment would also be impacted by changes in estimated future net revenues, which are impacted by additions and revisions to oil and natural gas reserves, as well as by sales and acquisitions of properties.

Borrowing base for the Credit Facility. The Credit Facility with Fortis Capital Corp. as administrative agent, is presently scheduled for borrowing base redetermination dates on a semi-annual basis with the next such redetermination scheduled for October 31, 2009. 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.

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 variable interest rate and fixed interest rate borrowings. Our long-term borrowings primarily consist of borrowings under the amended Credit Facility. Interest charged on borrowings under the amended Credit Facility floats with prevailing interest rates. Changes in interest rates will change the cost of borrowing. Our default under the Credit Facility poses a more significant interest rate risk, as we may not be able to continue to borrow at the rates currently in place. Further, we are in payment default with respect to $34.5 million of the outstanding borrowings under the Credit Facility. There can be no assurance that the Company will obtain concessions from the Lenders or be able to execute other alternatives to replace this borrowed capital at the current rates.

Assuming $94.5 million remains borrowed under the amended Credit Facility or a successor debt agreement, we estimate our annual interest expense will change by $0.95 million for each 100 basis point change in the applicable interest rates.

Hedging Contracts

Management of Financial Risk. The Company s operating environment includes two primary financial risks which could be addressed through derivatives and similar financial instruments: the risk of movement in oil and natural gas commodity prices, which impacts revenue, and the risk of interest rate movements, which impacts interest expense from floating rate debt.

The Company currently does not utilize derivative contracts or any other form of hedging against interest rate risk.

The Company utilizes derivative contracts to address the risk of adverse oil and natural gas commodity price fluctuations. While the use of derivative contracts limits the downside risk of adverse price movements, it may also limit future gains from favorable movements. No derivative contracts have been entered into for trading purposes, and the Company has the intent to hold each instrument to maturity.

The Company s commodity derivative contracts are considered cash flow hedges under generally accepted accounting principles.

Oil and Natural Gas Hedging Contracts. The Company has historically utilized derivative contracts to hedge the sale of a portion of its future production. The Company s objective is to reduce the impact of commodity price fluctuations on both income and cash flow, as well as to protect future revenues from adverse price movements. Management considered some exposure to market pricing to be desirable, due to the potential for favorable price movements, but preferred to achieve a measure of stability and predictability over revenues and cash flows by hedging some portion of production. The Company s commodity derivative positions as of June 30, 2009 hedge approximately 31% of proved developed natural gas production and 12% of proved developed oil production during the remaining terms of all derivative agreements in the aggregate.

The Company has historically chosen derivative contracts in the form of costless collars. These agreements ensured the Company would receive a minimum (floor) price for the commodity, while concurrently limiting the price to a specified maximum (ceiling). Typically, the contracts specify monthly hedged volumes subject to the floor and ceiling prices over a period of 6 to 18 months. The contracts are settled monthly based on the NYMEX futures contract. Counter parties to these contracts are large financial institutions that are members of the lending group which is party to our amended Credit Facility. The following table lists all of the Company s commodity derivative contracts as of June 30, 2009:

	Type	Notional Amount	Floor Price ($ per unit)	Ceiling Price ($ per unit)	Estimated Fair Value Asset (Liability) June 30, 2009 (in thousands)
Natural Gas (mmbtu)					
July 2009 Dec 2009	Collar	530,000	$ 7.50	$ 10.45	$ 1,691
July 2009 Dec 2009	Collar	330,000	$ 8.00	$ 10.30	1,205
July 2009 Dec 2009	Collar	230,000	$ 8.00	$ 13.35	842
Total Natural Gas					3,738
Crude Oil (bbls)					
July 2009 Dec 2009	Collar	11,000	$ 70.00	$ 93.55	41
July 2009 Dec 2009	Collar	16,000	$ 80.00	$ 111.00	172
July 2009 Dec 2009	Collar	21,000	$ 85.00	$ 128.50	314
Total Crude Oil					527
					$ 4,265

The above excludes the effect of certain modifications to five of the hedges made after June 30, 2009. See Note 15 in the accompanying Notes to Consolidated Financial Statements for additional information.

Special terms in derivative contracts. Although the Company s counterparties provide no collateral, the master derivative agreements with each counterparty effectively allow the Company, at its option, so long as it is not a defaulting party, after a default or the occurrence of a termination event, to set-off an unpaid hedging agreement receivable against the interest of the counterparty in any outstanding balance under the Credit Facility. In practice, no such set-off has been made, and all settlements have been made in cash. As of December 31, 2008, however, the Company is in covenant default under the Credit

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Facility, the breach of which is also a default under the master derivative agreements. Although the Company s hedge counterparties have continued to make contract payments subsequent to its default, they are not obligated to make payments to the Company under the hedging agreements while the Company s default is continuing. The Company s set-off rights under the master derivative agreements cannot be exercised due to such default. The Company s hedging counterparties may exercise their remedies under the hedging agreements, and potentially under the Credit Facility, on account of the Company s default, which includes a right to terminate the agreements and set-off any settlement amount due to the Company against amounts owed under the Credit Facility. The settlement amount would be based on the estimated value of the remaining forward portion of the contracts based on market values at settlement.

If a counterparty were to default in payment of an obligation under the master derivative agreements, the Company would be exposed to commodity price fluctuations, and the protection intended by the hedge would be lost. The value of assets from price risk management would be impacted. In addition, as expected cash flows from hedging contracts are included in computing future net revenues, the ceiling test could be impacted, which could result in a non-cash write-down of oil and natural gas properties.

ITEM 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We conducted an evaluation under the supervision of 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-15(e) under the Securities Exchange Act of 1934) as of the end of the second quarter of 2009. 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 during the first half of 2009 that could significantly affect these controls.

Changes in Internal Controls

During the six month period ended June 30, 2009, there were no changes in the Company s internal control over financial reporting that have materially affected or are reasonably likely to materially affect such internal control over financial reporting.

PART II OTHER INFORMATION

ITEM 1. Legal Proceedings.

Default under Credit Agreement. As described in Notes 1 and 6, the Company is in default under the terms of the credit facility, the master derivative agreements, and the rig note. The lead or administrative lenders under each of these agreements have been informed of the circumstances of default under the credit facility. On April 13, 2009, the lenders notified the Company that, effective April 30, 2009, the borrowing base was reduced from its current $95 million to $60 million. The credit facility provides that outstanding borrowings in excess of the borrowing base must be repaid within 90 days after the redetermination. The Company did not pay within the 90-day time frame and does not currently have sufficient cash available to repay the shortfall. Also among the remedies available to lenders under each of these agreements is acceleration of all principal and interest payments. Accordingly, all debts noted above, including the rig note, have been classified as current in the Consolidated Balance Sheets as of December 31, 2008 and June 30, 2009. The Company is currently unable to predict what further actions the lenders may pursue; therefore, the Company has not provided for this matter in its financial statements at June 30, 2009, other than to reclassify all outstanding debt as current.

The counterparties under the master derivative agreements have not notified the Company of action they may take, if any, due to the default under those agreements, which arises strictly from the default under the Credit Facility.

Litigation

H. L. Hawkins litigation. In December 2004, the estate of H.L. Hawkins filed a claim against Meridian for damages estimated to exceed several million dollars for Meridian s alleged gross negligence, willful misconduct and breach of fiduciary duty under certain agreements concerning certain wells and property in the S.W. Holmwood and E. Lake Charles Prospects in Calcasieu Parish in Louisiana, as a result of Meridian s satisfying a prior adverse judgment in favor of Amoco Production Company. Mr. James Bond had been added as a defendant by Hawkins claiming Mr. Bond, when he was General Manager of Hawkins, did not have the right to consent, could not consent or breached his fiduciary duty to Hawkins if he did consent to all actions taken by Meridian. Mr. James T. Bond was employed by H.L. Hawkins Jr. and his companies as General Manager until 2002. He served on the Board of Directors of the Company from March 1997 to August 2004. After Mr. Bond s employment with Mr. Hawkins, Jr., and his companies ended, Mr. Bond was engaged by The Meridian Resource & Exploration LLC as a consultant. This relationship continued until his death. Mr. Bond was also the father-in-law of Michael J. Mayell, the Chief Operating Officer of the Company at the time. A hearing was held before Judge Kay Bates on April 14, 2008. Judge Bates granted Hawkins Motion finding that Meridian was estopped from arguing that it did not breach its contract with Hawkins as a result of the United States Fifth Circuit s decision in the *Amoco* litigation. Meridian disagrees with Judge Bates ruling but the Louisiana First Court of Appeal declined to hear Meridian s writ requesting the court overturn Judge Bates ruling. Meridian filed a motion with Judge Bates asking that the ruling be made a final judgment which would give Meridian the right to appeal immediately; however, the Judge declined to grant the motion, allowing the case to proceed to trial. Management continues to vigorously defend this action on the basis that Mr. Hawkins individually and through his agent, Mr. Bond, agreed to the course of action adopted by Meridian and further that Meridian s actions were not grossly negligent, but were within the business judgment rule. Since Mr. Bond s death, a pleading has been filed substituting the proper party for Mr. Bond. The Company is unable to express an opinion with respect to the likelihood of an unfavorable outcome of this matter or to estimate the amount or range of potential loss should the outcome be unfavorable. Therefore, the Company has not provided any amount for this matter in its financial statements at June 30, 2009.

Parsons Exploration litigation. On May 3, 2007, Parsons Exploration Company, LLC (Parsons) filed a claim against Meridian for damages and specific performance requiring Meridian to assign Parsons an overriding royalty interest in certain wells the Company has drilled in east Texas. The complaint alleged that the Company breached its contractual and fiduciary obligations to Parsons under an Exploration and Prospect Origination Agreement between the parties dated April 22, 2003. The complaint also alleged that the Company engaged in a civil conspiracy to breach its contractual and fiduciary obligations to Parsons and tortiously interfered with existing and prospective business relationships/contracts of Parsons. The Company recognized an estimated settlement for this matter in the amount of $2.1 million in the first quarter of 2009, which was charged to the full cost pool. The parties reached a final confidential settlement agreement in the second quarter of 2009.

Title/lease disputes. Title and lease disputes may arise in the normal course of the Company s operations. These disputes are usually small but could result in an increase or decrease in reserves once a final resolution to the title dispute is made.

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Environmental litigation. Various landowners have sued Meridian (along with numerous other oil companies) in lawsuits concerning several fields in which the Company has had operations. The lawsuits seek injunctive relief and other relief, including unspecified amounts in both actual and punitive damages for alleged breaches of mineral leases and alleged failure to restore the plaintiffs lands from alleged contamination and otherwise from the Company s oil and natural gas operations. In some of the lawsuits, Shell Oil Company and SWEPI LP (together, Shell) have demanded contractual indemnity and defense from Meridian based upon the terms of the two acquisition agreements related to the fields, and in another lawsuit, Exxon Mobil Corporation has demanded contractual indemnity and defense from Meridian on the basis of a purchase and sale agreement related to the field(s) referenced in the lawsuit; Meridian has challenged such demands. In some cases, Meridian has also demanded defense and indemnity from their subsequent purchasers of the fields. On December 9, 2008 Shell sent Meridian a letter reiterating its demand for indemnity. Shell has not to date produced all of the supporting documentation for its claim. Shell initiated formal arbitration proceedings on May 11, 2009, seeking relief only for the claimed costs and expenses arising from one of the two acquisition agreements between Shell and Meridian. An arbitration panel has been selected and an initial conference was held with the panel on July 31, 2009. The two companies have entered into settlement discussions. Meridian denies that it owes any indemnity under either of the two acquisition agreements; however, the amounts claimed are substantial in nature and if adversely determined, would have a material adverse effect on the Company. The Company is unable to express an opinion with respect to the likelihood of an unfavorable outcome of these matters or to estimate the amount or range of potential loss should any outcome be unfavorable. Therefore, the Company has not provided any amount for these matters in its financial statements at June 30, 2009.

Litigation involving insurable issues. There are no material legal proceedings involving insurable issues which exceed insurance limits to which Meridian or any of its subsidiaries 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 1A. Risk Factors.

The following are updates to certain of the risk factors that appear in our annual report on Form 10-K for the year ended December 31, 2008. Each of the following risk factors could adversely affect our business, operating results and financial condition. It is not possible to foresee or identify all such factors. Investors should not consider this list or the list of risk factors contained in our most recent Form 10-K an exhaustive statement of all risks and uncertainties. This report and our most recent Form 10-K also contain forward-looking statements that involve risks and uncertainties. Our actual results may differ from those anticipated in these forward-looking statements as a result of both the risks described below and factors described elsewhere in this report and in our most recent Form 10-K. You should read the sections in our most recent Form 10-K entitled Risk Factors and Forward-Looking Statements for further discussion of these matters.

We are currently in payment default under our Credit Facility and in covenant default under certain of the covenants in our Credit Facility. Such covenant and payment defaults under the Credit Facility have resulted in defaults under hedging agreements we have entered into with certain affiliates of Fortis Capital Corp. and Scotia Bank due to cross default provisions therein. Furthermore, as a result of such defaults under the Credit Facility, we are also in default under our drilling rig financing with CIT Group/Equipment Financing, Inc. due to cross default provisions therein. We will have difficulty returning to compliance with the Credit Facility, the hedging agreements and the drilling rig financing, and if we are unable to return to compliance, our lenders may exercise remedies that would have a material adverse effect on us and our shareholders.

Under our Credit Facility, our most recent scheduled redetermination of our borrowing base was effective April 30, 2009, at which time the borrowing base was reduced to $60 million from $95 million. As of the date hereof, we have outstanding indebtedness of approximately $94.5 million under the Credit Facility.

The Credit Facility provides that outstanding borrowings in excess of the borrowing base must be repaid within 90 days after the date of redetermination. Accordingly, a $34.5 million payment to our Lenders for the borrowing base deficiency was due July 29, 2009. We do not currently have sufficient cash available to repay the deficiency and, consequently, we failed to pay such amount when due and are in default under the Credit Facility for such failure.

In addition to such default for failure to pay the borrowing base deficiency, there are other covenant defaults existing under the Credit Facility. Such covenant and payment defaults under the Credit Facility have resulted in defaults under hedging agreements we have entered into with certain affiliates of Fortis Capital Corp. and Scotia Bank due to cross default provisions therein. The Company is currently in discussions with the Lenders and Fortis and Scotia Bank hedge counterparties regarding entering into forbearance agreements pursuant to which such parties would forbear for an agreed period of time from exercising remedies otherwise available to them as a result of such existing covenant and payment defaults. We cannot provide any assurance that the Lenders or Fortis hedge counterparties will agree to any such arrangements.

As a result of the payment default for the borrowing base deficiency and financial covenant defaults under the Credit Facility, we are also in default under our drilling rig financing with CIT Group/Equipment Financing, Inc. due to cross default provisions therein. We currently owe approximately $8 million to CIT under the drilling rig financing, and we have additional substantial financial obligations under related drilling rig contracts. We currently are in discussions with CIT regarding entering into a forbearance agreement pursuant to which CIT would forbear for an agreed period of time from exercising remedies otherwise available to it as a result of such existing covenant and payment defaults. We cannot provide any assurance that CIT will agree to any such arrangements.

We are pursuing other options for repayment of our indebtedness, including the sale of strategic and nonstrategic assets or obtaining capital from other sources. We may not be able to sell assets on terms that we consider advantageous to us and our shareholders, and capital on acceptable terms may not be available from other sources. If we are unable to obtain concessions from our Lenders, CIT and the hedge counterparties and execute other alternatives, we would continue to be in default under the Credit Facility, the CIT financing and the hedge agreements and we would be subject to the exercise of remedies by such parties on account of such defaults. The exercise of such remedies could potentially result in us seeking protection under federal bankruptcy laws. Such relief could materially and adversely affect the Company and its shareholders.

Our common stock could be delisted from the New York Stock Exchange.

As of December 4, 2008, we received notification from the New York Stock Exchange (NYSE) that the Company had fallen below certain continued listing criteria that require a minimum average closing price of $1.00 per share over 30 consecutive trading days. The NYSE temporarily suspended the minimum average closing price requirement during part of the first half of 2009, but we recently received oral notification from the NYSE that our common stock will be delisted if we are not in compliance with that requirement by November 9, 2009. In addition, we are currently monitoring the Company s compliance with another listing criterion. This criterion requires that average market capital over 30 consecutive trading days must be at least $15 million. Based on shares currently outstanding, the Company s average market capital decreases below this level when the stock price drops below approximately $0.16 per share. Some closing prices in the first half of 2009 have been below this price. If the Company becomes non-compliant with this criterion, our common stock will be immediately subject to the NYSE s delisting procedures.

The Company is also non-compliant with an NYSE listing criterion which requires that a majority of our directors be independent. We have ten directors, of which four are independent.

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There can be no assurance that the stock of the Company will continue to be listed on the NYSE; there can be no assurance that we will obtain listing on an alternate stock exchange or automated quotation service. A delisting of our common stock could materially and adversely affect, among other things, the liquidity and market price of our common stock; the number of investors willing to hold or acquire our common stock; and our access to capital markets to raise capital in the future.

ITEM 6. 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 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 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.

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 10, 2009

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