MERIDIAN RESOURCE CORP
Form 10-Q
May 11, 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: March 31, 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 the definitions 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 May 1, 2009: 93,070,592

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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 March 31, 2009	2008
REVENUES:		
Oil and natural gas	$ 22,109	$ 38,448
Price risk management activities	2	(34)
Interest and other	21	127
	22,132	38,541
OPERATING COSTS AND EXPENSES:		
Oil and natural gas operating	4,629	6,070
Severance and ad valorem taxes	1,635	2,578
Depletion and depreciation	11,763	17,742
General and administrative	3,369	4,075
Accretion expense	523	567
Impairment of long-lived assets	59,539	
	81,458	31,032
EARNINGS (LOSS) BEFORE OTHER EXPENSE & INCOME TAXES	(59,326)	7,509
OTHER EXPENSE:		
Interest expense	1,634	1,151
EARNINGS (LOSS) BEFORE INCOME TAXES	(60,960)	6,358
INCOME TAXES:		
Current	1	107
Deferred	0	2,688
	1	2,795
NET EARNINGS (LOSS)	$ (60,961)	$ 3,563
NET EARNINGS (LOSS) PER SHARE:		
Basic	$ (0.66)	$ 0.04

Diluted	$	(0.66)	$	0.04
WEIGHTED AVERAGE NUMBER OF COMMON SHARES:				
Basic		92,451		89,356
Diluted		92,451		95,302

See notes to consolidated financial statements.

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

	March 31, 2009 (unaudited)	December 31, 2008
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 5,082	$ 13,354
Restricted cash	9,968	9,971
Accounts receivable, less allowance for doubtful accounts of $210 [2009 and 2008]	12,454	16,980
Prepaid expenses and other	863	3,292
Assets from price risk management activities	8,411	8,447
Total current assets	36,778	52,044
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, full cost method (including $30,295 [2009] and $39,927 [2008] not subject to depletion)	1,890,627	1,877,925
Land	48	48
Equipment and other	21,372	21,371
	1,912,047	1,899,344
Less accumulated depletion and depreciation	1,718,798	1,647,496
Total property and equipment, net	193,249	251,848
OTHER ASSETS:		
Other	379	683
Total other assets	379	683
TOTAL ASSETS	$ 230,406	$ 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)

	March 31, 2009 (unaudited)	December 31, 2008
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 7,774	$ 15,097
Advances from non-operators	2,142	5,517
Revenues and royalties payable	5,316	6,267
Due to affiliates	8,234	8,145
Notes payable	202	1,775
Accrued liabilities	19,101	18,831
Liabilities from price risk management activities	47	311
Asset retirement obligations	353	1,457
Current income taxes payable	45	47
Current maturities of long-term debt	103,405	103,849
Total current liabilities	146,619	161,296
LONG-TERM DEBT		
OTHER:		
Asset retirement obligations	22,917	20,768
	22,917	20,768
COMMITMENTS AND CONTINGENCIES (Note 8)		
STOCKHOLDERS EQUITY:		
Common stock, $0.01 par value (200,000,000 shares authorized, 93,070,592 [2009] and 93,045,592 [2008] issued)	948	948
Additional paid-in capital	538,614	538,561
Accumulated deficit	(483,949)	(422,028)
Accumulated other comprehensive income	8,356	8,129
	63,969	125,610
Less treasury stock, at cost 1,712,114 [2009] and [2008]shares	3,099	3,099
Total stockholders equity	60,870	122,511

TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 230,406	$ 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)

	Three Months Ended March 31,	
	2009	**2008**
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net earnings (loss)	$ (60,961)	$ 3,563
Adjustments to reconcile net earnings (loss) to net cash provided by operating activities:		
Depletion and depreciation	11,763	17,742
Impairment of long-lived assets	59,539	
Amortization of other assets	304	20
Non-cash compensation	53	613
Non-cash gain on change in fair value of outstanding warrants	(641)	
Non-cash price risk management activities	(2)	34
Accretion expense	523	567
Deferred income taxes		2,688
Changes in assets and liabilities:		
Restricted cash	4	(1)
Accounts receivable	3,927	(1,573)
Prepaid expenses and other	2,429	2,609
Due to/from affiliates	89	1,557
Accounts payable	(3,448)	(442)
Advances from non-operators	(3,376)	(5,433)
Revenues and royalties payable	(951)	141
Asset retirement obligations		(269)
Other assets and liabilities	(497)	950
Net cash provided by operating activities	8,755	22,766
CASH FLOWS USED IN INVESTING ACTIVITIES:		
Additions to property and equipment	(15,009)	(38,317)
Proceeds from sale of property		4,562
Net cash used in investing activities	(15,009)	(33,755)
CASH FLOWS PROVIDED BY (USED IN) FINANCING ACTIVITIES:		
Proceeds from long-term debt		10,000
Reductions to long-term debt	(445)	
Reductions in notes payable	(1,573)	(2,447)
Additions to deferred loan costs		(703)
Net cash provided by (used in) financing activities	(2,018)	6,850
NET CHANGE IN CASH AND CASH EQUIVALENTS	(8,272)	(4,139)

Cash and cash equivalents at beginning of period		13,354		13,526
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$	5,082	$	9,387
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION				
Increase (decrease) of Non-cash Activities:				
Accrual of capital expenditures	$	(2,826)	$	(7,577)
ARO liability new wells drilled	$		$	17
ARO liability changes in estimates	$	522	$	(1,729)

See notes to consolidated financial statements.

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THE MERIDIAN RESOURCE CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY
Three Months Ended March 31, 2009 and 2008
(in thousands)
(unaudited)

	Common Stock		Additional Paid-In	Accumulated Earnings	Accumulated Other Comprehensive Income	Treasury Stock		
	Shares	Par Value	Capital	(Deficit)	(Loss)	Shares	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			40					40
Compensation expense			443					443
Accumulated other comprehensive loss					(3,702)			(3,702)
Net earnings				3,563				3,563
Balance, March 31, 2008	89,450	$ 939	$ 537,622	$ (208,579)	$ (3,923)	87	$ (155)	$ 325,904
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)
Stock-based compensation	25		53					53
Accumulated other comprehensive income					227			227
Net loss				(60,961)				(60,961)

Balance, March 31, 2009	93,070	$ 948	$ 538,614	$ (483,949)	$ 8,356	(1,712)	$ (3,099)	$ 60,870

See notes to consolidated financial statements.

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

	Three Months Ended March 31,	
	2009	**2008**
Net earnings (loss)	$ (60,961)	$ 3,563
Other comprehensive income (loss), net of tax, for unrealized gains (losses) from hedging activities:		
Unrealized holding gains (losses) arising during period (1)	3,798	(4,094)
Reclassification adjustments on settlement of contracts (2)	(3,571)	392
	227	(3,702)
Total comprehensive loss	$ (60,734)	$ (139)
(1) Net income tax (expense) benefit	$	$ 2,204
(2) Net income tax (expense) benefit	$	$ (211)

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 March 31, 2009, and for the three month periods ended March 31, 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 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.

As of December 31, 2008 and March 31, 2009, the Company is in default of two covenants under its revolving credit facility. The Company s current ratio, as defined in the credit facility, was below the required 1.0 ratio. 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.

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. 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 does not currently have sufficient cash available to repay the shortfall. The borrowing base is determined at the discretion of the lenders, based primarily on the value of the Company s proved reserves. The value of proved reserves has been significantly reduced during the last several months due primarily to continuing decreases in the prices of oil and natural gas. Management is currently in discussions with the lenders regarding alternative repayment terms, including consideration of amortization payments from cash flow, obtaining waivers for non-compliance with covenants creating events of default, providing additional security, and the potential for a forbearance agreement. No assurance can be provided that the lenders will agree to any such arrangements. Management is also considering other options for repayment, including the sale of strategic and nonstrategic assets and 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, or at all. The Company s inability to obtain concessions from the lenders or to execute other alternatives would have a material adverse effect on results of operations and financial condition.

The Company has master derivative agreements with two of the Lenders under the Credit Facility, which by virtue of the default under the Credit Facility, are also in default. The counterparties under the master derivative contracts have not notified the Company of the action they intend to pursue as a result of the event of default, if any; see Note 11 for further information.

The Company is also in default of its other bank debt, a five-year $8.4 million loan, payable in monthly installments of approximately $196,000, which was used to purchase a drilling rig (rig note.) Under the terms of the rig note, any non-compliance or default under the terms of the credit facility triggers a default under the terms of the rig note, as well. The remedies available to the lender under the rig note also include acceleration of all principal and interest payments. The lender under the rig note was timely advised of the default under the covenants of the credit facility and may respond with a declaration of default under the rig note. The lender may accelerate all payments of principal and interest in response to an event of default, or may elect to take other action.

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.

2. 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 hedges positions, discounted at 10%, 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.

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.

At March 31, 2009, the Company had no cushion (i.e., the excess of the ceiling over our capitalized costs). Thus, any decrease in prices affecting the end of subsequent accounting periods, net of the effect of hedging positions, may require the Company to record 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. A 10% decrease in prices would have increased 2009 non-cash impairment expense by approximately $25.9 million or 44%.

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 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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3. SIGNIFICANT ACCOUNTING POLICIES

Drilling Rig

TMR Drilling Corporation (TMRD), a wholly owned subsidiary of the Company, owns a rig which is used primarily to drill wells operated by the Company. In April 2008, an unaffiliated service company, Orion Drilling, Ltd, 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 our joint interest partners, are offset against the full cost pool. SEC guidelines for full cost accounting require this method in cases where services are performed by a company on properties that it owns and/or manages.

When the rig is used by the service company 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 statement of operations. During the three months ended March 31, 2009, the rig worked entirely on third party wells, at an estimated breakeven profit to the Company. Accordingly, no profit or loss has been recorded as income for that period.

Restricted Cash, Rabbi Trust, and Treasury Stock

The Company classifies cash balances as restricted cash when cash is restricted as to withdrawal or usage. The restricted cash balance at December 31, 2008, was $9,971,000 and at March 31, 2009, was $9,968,000. 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 is related to a contractual obligation with respect to royalties payable.

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. Both the shares and the cash from the trust will be distributed to the former officers upon dissolution of the trust, anticipated for the second quarter of 2009. Until distribution, the assets of the trust belong to the Company, but are effectively restricted due to the obligation to the officers.

The shares in the trust will be accounted for as treasury shares so long as they remain in the trust. As of March 31, 2009, the Company has no other shares in treasury.

Recent Accounting Pronouncements

In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, Fair Value Measurements (SFAS 157). SFAS 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosure about fair value measurements. The standard applies prospectively to new fair value measurements performed after the required effective dates, which are as follows: on January 1, 2008, for the Company, the standard became applicable to measurements of the fair values of financial instruments and recurring fair value measurements of non-financial assets and liabilities; on January 1, 2009, for the Company, the standard became effective for all remaining fair value measurements, including non-recurring measurements of non-financial assets and liabilities, such as asset retirement obligations and impairments of long-lived assets. We adopted the provisions of SFAS 157 for the fair values of financial instruments on January 1, 2008. Beginning January 1, 2009, we applied SFAS 157 to non-financial assets and liabilities. The adoption of SFAS No. 157 did not have a material impact on financial position or results of operations of the Company.

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In December 2007, the FASB issued SFAS No. 141(R), Business Combinations. SFAS 141(R) replaces SFAS No. 141, Business Combinations. SFAS 141(R) retains the purchase method of accounting for acquisitions, but requires a number of changes, including changes in the way assets and liabilities are recognized in purchase accounting. It also changes the recognition of assets acquired and liabilities assumed arising from contingencies and requires the expensing of acquisition-related costs as incurred. Generally, SFAS 141(R) is effective on a prospective basis for all business combinations completed on or after January 1, 2009. We adopted SFAS 141(R) as of January 1, 2009 and do not expect it to have a material impact on our financial position or results of operations, provided we do not undertake a significant acquisition or business combination.

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 11.

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 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 year-end prices. The use of average prices will affect future impairment and depletion calculations.

The new disclosure requirements are effective for annual reports on Forms 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 three FASB Staff Positions (FSP s) to provide additional application guidance and enhance disclosures regarding fair value measurements and impairments of securities. FSP FAS 157-4, *Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly,* provides guidelines for making fair value measurements more consistent with the principles presented in SFAS No. 157. FSP FAS 107-1 and APB 28-1, *Interim Disclosures about Fair Value of Financial Instruments,* enhances consistency in financial reporting by increasing the frequency of fair value disclosures. FSP FAS 115-2 and FAS 124-2, *Recognition and Presentation of Other-Than-Temporary Impairments,* provides

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additional guidance designed to create greater clarity and consistency in accounting for and presenting impairment losses on securities. These three FSP s are effective for interim and annual periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. We will adopt these FSP s effective April 1, 2009 and do not anticipate the adoption will have a material impact on financial position or results of operations of the Company.

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 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 annually under the provisions of SFAS 107, *Disclosures about Fair Value of Financial Instruments*, and will begin to provide quarterly upon adoption 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 has 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 3 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 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 3 and 9) were valued using the Black-Scholes option pricing model.

Assets and liabilities measured at fair value on a recurring basis

			Fair Value Measurements at March 31, 2009 Using (thousands of dollars)		
Description		March 31, 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)	$8,411		$ 8,411	
Liabilities from price risk management activities	(1)	$ 47		$ 47	
General partner warrants	(2)	$ 320		$ 320	

(1) Assets and liabilities from price risk management activities are oil and natural gas derivative contracts, in the form costless

collars to sell oil and natural gas within specific future time periods. These contracts are more fully described in Note 11.

(2) General partner warrants are more fully described in Note 9.

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As noted above, FAS 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. There were no new asset retirement obligations measured at fair value during the three months ended March 31, 2009.

5. ACCRUED LIABILITIES

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

	March 31, 2009	December 31, 2008
Capital expenditures	$ 8,672	$ 8,227
Operating expenses/taxes	3,763	4,452
Hurricane damage repairs	919	1,555
Compensation	3,389	2,478
Interest	378	261
General partner warrants	320	
Other	1,660	1,858
Total	$ 19,101	$ 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. The borrowing base under the Credit Facility was redetermined by the syndication group to be $115 million effective October 31, 2007.

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 250 basis points on the lower end of the range and by 500 basis points on the higher end of the range; the range of the add-on to the alternative base rate was increased by 250 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 500 basis points on the lower end of the range and by 750 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 terms of the Credit Facility contain numerous covenants and restrictions. Currently, the Company is

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in default of a covenant which requires that it 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 both December 31, 2008 and March 31, 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 default, the outstanding Credit Facility balance of $95 million at December 31, 2008 and March 31, 2009 has been classified in current liabilities on the accompanying consolidated balance sheets.

The Lenders were informed of the defaults under the covenants. 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. 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 does not currently have sufficient cash available to repay the shortfall. The borrowing base is determined at the discretion of the Lenders, based primarily on the value of the Company s proved reserves. The value of proved reserves has been significantly reduced during the last several months due primarily to continuing decreases in the prices of oil and natural gas. Management is currently in discussions with the Lenders regarding repayment terms, including consideration of amortization payments from cash flow, obtaining waivers for non-compliance with covenants creating events of default, providing additional security, and the potential for a forbearance agreement. No assurance can be provided that the Lenders will agree to any such arrangements. Management is also considering other options for repayment, including the sale of strategic and nonstrategic assets and 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, or at all. The Company s inability to obtain concessions from the Lenders or to execute other alternatives would have a material adverse effect on results of operations and financial condition.

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.

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. 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 March 31, 2009, the Company was in default of two of these covenants.

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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 March 31, 2009 it was 1.19%, 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 May 1, 2009, outstanding borrowing under the Credit Facility totaled $95.0 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 an event of default under the rig note. The remedies available to CIT in the event of default include acceleration of all principal and interest payments. All indebtedness under the rig note, $8.8 million at December 31, 2008 and $8.4 million at March 31, 2009, has been classified in current liabilities on the accompanying consolidated balance sheets as of December 31, 2008 and March 31, 2009.

CIT was notified of the Company s defaults under the covenants of the Credit Facility, and has not responded with a notice of any remedies it may choose to pursue.

7. INCOME TAXES

The Company s effective income tax rate has varied significantly in recent periods. In the first quarter of 2008, our effective income tax rate was 44%, 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, we recorded significant non-cash impairment losses (see Note 2). Generally Accepted Accounting Principles require 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 in 2008 to the full extent of all net deferred tax assets. The allowance was adjusted in the first quarter of 2009 to maintain this complete offset of all deferred tax assets. Thus, the tax benefit related to net losses recognized in the first quarter was zero, and the effective tax rate for that period is 0%.

In the fourth quarter of 2008, we were notified by the Internal Revenue Service that Meridian would be audited for fiscal years 2006 and 2007. The audit is near completion and the Company does not expect a material impact on financial position or results of operations.

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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 March 31, 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 has recognized an estimated settlement for this matter in the amount of $2.1 million, which was charged to the full cost pool in the first 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 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

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demand for indemnity. Shell has not to date produced all of the supporting documentation for its claim. In the Company s discussions with Shell, Shell has indicated that it is considering filing an arbitration, but has not yet initiated a formal proceeding. Meridian denies that it owes any indemnity under the 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 March 31, 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.

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 March 31, 2009, the Company had no cushion (i.e., the excess of the ceiling over capitalized costs). Thus, any decrease 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. A 10% decrease in prices would have increased our 2009 non-cash impairment expense by approximately $25.9 million or 44%.

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 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.

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 $2.4 million insurance receivable at March 31, 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.

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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 been cooperative in actively seeking other parties to use the rigs, and in agreeing to credit the Company s obligation to some extent, based on revenues from other 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 quarter of 2009, one rig has been effectively subleased to others, but for short duration, 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, such that for the first quarter of 2009, the dayrate shortfall is estimated to have been offset by the Company share of rig operations profit and no loss has been recognized. The other rig continued to be utilized drilling a Meridian-operated well through the end of the quarter, although it has subsequently been released by Meridian, and is currently under short-term contract to a third party. Management cannot predict whether such use by third parties will be consistent, nor to what extent it may offset obligations under the dayrate contract. The Company has not provided any amount for these matters in its financial statements at March 31, 2009. Expenditures for the rigs when they are not drilling for the Company are expected to be expensed as they occur.

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. During February 2007, 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 March 31, 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 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 three months ended March 31, 2009, the Company recorded a gain on the valuation of the warrants of $641,000, 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.

There were 1,885,052 General Partner Warrants outstanding at March 31, 2009, included in accrued liabilities at a total fair value of $320,000. Fair value is based on the Black-Scholes model for option pricing.

10. EARNINGS PER SHARE

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

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	Three Months Ended March 31,	
	2009	**2008**
Numerator:		
Net earnings (loss)	$ (60,961)	$ 3,563
Denominator:		
Denominator for basic earnings per share weighted-average shares outstanding	92,451	89,356
Effect of potentially dilutive common shares:		
Warrants and stock rights (a)	NA	5,946
Employee and director stock options (a)	NA	NA
Denominator for diluted earnings per share weighted-average shares outstanding and assumed conversions	92,451	95,302
Basic earnings (loss) per share	$ (0.66)	$ 0.04
Diluted earnings (loss) per share	$ (0.66)	$ 0.04

(a) The number of warrants excluded for the three months ended March 31, 2009 totaled approximately 3.3 million. The number of options excluded for that period totaled approximately 0.7 million. A total of 3.4 million options were excluded for the three months ended March 31, 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 quarter of 2009, had no exercise price and are included in diluted earnings per share for the three months ended March 31, 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.

11. 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.
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 SFAS 133.

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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 March 31, 2009 hedge approximately 29% of proved developed natural gas production and 16% 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 March 31, 2009:

		Type	Notional Amount	Floor Price ($ per unit)	Ceiling Price ($ per unit)	Estimated Fair Value Asset (Liability) March 31, 2009 (in thousands)
Natural Gas (mmbtu)						
Apr 2009	Dec 2009	Collar	860,000	$ 7.50	$ 10.45	$ 2,866
Apr 2009	Dec 2009	Collar	530,000	$ 8.00	$ 10.30	2,012
Apr 2009	Dec 2009	Collar	360,000	$ 8.00	$ 13.35	1,367
					Total Natural Gas	6,245
Crude Oil (bbls)						
Apr 2009	Dec 2009	Collar	17,000	$ 70.00	$ 93.55	298
Apr 2009	Dec 2009	Collar	28,000	$ 80.00	$ 111.00	751
Apr 2009	Dec 2009	Collar	34,000	$ 85.00	$ 128.50	1,070
					Total Crude Oil	2,119
						$ 8,364

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 fair value, 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 $3,571,000 and ($603,000) for the three months ended March 31, 2009 and 2008, respectively. A gain or loss may be recorded to earnings prior

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to contract maturity if a portion of the cash flow hedge becomes ineffective under the guidelines provided by SFAS 133 and related interpretations, 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):

Description and location within Consolidated Balance Sheet	Fair Values of Derivative Contracts at March 31, 2009	December 31, 2008
Derivative contracts designated as hedging instruments under SFAS 133		
Commodities Contracts		
Current assets from price risk management activities	$ 8,411	$ 8,447
Non-current assets from price risk management activities		
Current liabilities from price risk management activities	$ 47	$ 311
Non-current liabilities from price risk management activities		
Derivative contracts not designated as hedging instruments under SFAS 133	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 March 31, 2009	March 31, 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	3,798	(6,298)
Gain (loss) on derivative contracts reclassified from OCI to earnings			
Commodities Contracts	Oil and Natural Gas Revenues	3,571	(603)
Gain (loss) due to hedging ineffectiveness reported in earnings			
Commodities Contracts	Revenues from Price Risk Management Activities	2	(34)
Fair value of derivative contracts designated as cash flow hedging instruments, excluded from effectiveness assessments		NONE	NONE
Derivative contracts not designated as hedging instruments		NONE	NONE

As of March 31, 2009, the Company had an unrealized gain of $8.4 million (pre-tax and net of tax) deferred in Accumulated Other Comprehensive Income. Based upon oil and natural gas commodity

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prices at March 31, 2009, all of the unrealized gain deferred in Accumulated Other Comprehensive Income could potentially increase gross revenues in the next nine months. These derivative agreements expire December 31, 2009.

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 and continuing at March 31, 2009, however, the Company is in default of two covenants contained in the Credit 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 set-off any amount due to the Company under the derivative agreements against amounts owed to that counterparty as a Lender under the Credit Facility.

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.

12. SHARE-BASED COMPENSATION

Stock Options

The Company records share-based compensation expense under the provisions of SFAS No. 123R, Share-Based Payment. Compensation expense is 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 $53,000 was recorded in the three months ended March 31, 2009 and $613,000 was recognized in the three month period ended March 31, 2008. 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.

13. 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 three months ended March 31, 2009, (thousands of dollars):

Asset retirement obligation at December 31, 2008	$ 22,225
Additional retirement obligations recorded in 2009	
Settlements during 2009	
Revisions to estimates and other changes during 2009	522
Accretion expense for 2009	523
Asset retirement obligation at March 31, 2009	23,270
Less: current portion	353
Asset retirement, long-term, at March 31, 2009	$ 22,917

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.

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

Operations Update

Production volumes for the first quarter of 2009 totaled 3.3 billion cubic feet of gas equivalent (Bcfe), or an average of 37.1 million cubic feet of natural gas equivalent per day (Mmcfe/d) compared to 3.7 Bcfe or 41.0 Mmcfe per day for the first quarter of 2008. The variance in production volumes between the two periods is due to natural production declines, offset in large part by new discoveries brought online since the first quarter of 2008. New discoveries affecting production between the periods include those in East Texas, Weeks Island, Ramos and Turtle Bayou. Currently, the overall average daily production for the Company ranges between 35 and 38 Mmcfe per day.

During the first quarter, Meridian completed the Goodrich-Cocke No. 7 in Weeks Island (tested at 900 Boe/d, 430 net) and the Myles Salt No. 27 in Weeks Island (tested at 770 Boe/d, 455 net). Construction on the previously announced Weeks Bay No. 15 well pipeline and production facility tie-in is substantially complete and the well will be turned over to production in the coming days. In late April 2009, the outside operated Davis A-39 well was tested at a gross daily rate as high as 20 Mmcfe per day (3.5 net). In the first week of production this well has averaged approximately 17.9 Mmcfe per day. The Company expects that the well will display similar producing characteristics to other Austin Chalk wells in the area, with the typical hyperbolic decline curve from current production levels during the coming months. Additional work was conducted on the Black Stone Minerals No. A-278 well in East Texas resulting in minimal improvement, and the well is currently considered to be uneconomic.

Capital Expenditure Plans for 2009

The Company anticipates the 2009 capital spending budget will be primarily used for recompletions and similar work on existing properties, and for lease maintenance costs. 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 the 2009 plan 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 March 31, 2009, was $45.62 per barrel compared to $86.91 per barrel for the three months ended March 31, 2008, and $53.47 per barrel for the three months ended December 31, 2008. Our average natural gas price (after adjustments for hedging activities) for the three months ended March 31, 2009, was $6.07 per Mcf compared to $8.55 per Mcf for the three months ended March 31, 2008, and $6.85 per Mcf for the three months ended December 31, 2008.

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, 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.

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 Issue 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 three months ended March 31, 2009, we recorded a $641,000 reduction of general and administrative expense due to the change in fair value of the warrants. 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 March 31, 2009 Compared to Three Months Ended March 31, 2008

Operating Revenues. First quarter 2009 oil and natural gas revenues, which include oil and natural gas hedging activities (see Note 11 of Notes to Consolidated Financial Statements), decreased $16.3 million (42%) as compared to first quarter 2008 revenues due to a 10% decrease in production volumes and a 36% decrease in average commodity prices on a natural gas equivalent basis. Oil and natural gas

production volumes totaled 3,340 Mmcfe for the first quarter of 2009 compared to 3,731 Mmcfe for the comparable period of 2008. Our average daily production decreased from 41 Mmcfe during the first quarter of 2008 to 37 Mmcfe for the first quarter of 2009. First 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 March 31, 2009 and 2008:

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008	Increase (Decrease)
Production Volumes:			
Oil (Mbbl)	199	184	8%
Natural gas (MMcf)	2,147	2,626	(18%)
Mmcfe	3,340	3,731	(10%)
Average Sales Prices:			
Oil (per Bbl)	$ 45.62	$ 86.91	(48%)
Natural gas (per Mcf)	$ 6.07	$ 8.55	(29%)
Mmcfe	$ 6.62	$ 10.31	(36%)
Operating Revenues (000 s):			
Oil	$ 9,071	$ 16,006	(43%)
Natural gas	$ 13,038	$ 22,442	(42%)
Total Operating Revenues	$ 22,109	$ 38,448	(42%)

Operating Expenses. Oil and natural gas operating expenses on an aggregate basis decreased $1.4 million (24%) to $4.6 million during the first quarter of 2009, compared to $6.1 million in the first quarter of 2008. On a unit basis, lease operating expenses decreased $0.24 per Mcfe to $1.39 per Mcfe for the first quarter of 2009 from $1.63 per Mcfe for the first quarter of 2008. Oil and natural gas operating expenses decreased primarily due to decreased workovers, lower insurance costs, reduced production, and cost saving measures implemented in the field.

Severance and Ad Valorem Taxes. Severance and ad valorem taxes decreased $0.9 million (37%) to $1.6 million for the first quarter of 2009, compared to $2.6 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 $0.49 per Mcfe from $0.69 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 $5.9 million (34%) during the first quarter of 2009 to $11.8 million, from $17.7 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 $1.24 per Mcfe, to $3.52 per Mcfe for the three months ended March 31, 2009, compared to $4.76 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-down to the properties recorded in December 2008.

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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.

General and Administrative Expense. General and administrative expense was $3.4 million in the first quarter of 2009 compared to $4.1 million in the first quarter of 2008. The $0.7 million decrease was primarily due to the non-cash mark to market reduction of $0.6 million in expenses in the first quarter of 2009 of the Company s General Partner Warrants; see Note 9 elsewhere in this report. On an equivalent unit of production basis, general and administrative expenses decreased $0.08 per Mcfe to $1.01 per Mcfe for the first quarter of 2009 compared to $1.09 per Mcfe for the comparable 2008 period primarily due to the expense reduction due to the General Partner Warrants, partially offset by lower production rates between the periods.

Interest Expense. Interest expense increased $0.4 million (42%), to $1.6 million for the first quarter of 2009 in comparison to $1.2 million for the first quarter of 2008. The increase is primarily a result of higher average debt balances. In addition, a portion of our deferred loan costs related to the Credit Facility were written off and charged to interest expense.

Taxes on Income. Income tax expense for the first quarter of 2009 was zero, compared to $2.8 million in the first 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 our overall current financial position, that there are significant uncertainties regarding our 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.

Liquidity and Capital Resources

Working Capital. During the first quarter of 2009, Meridian s capital expenditures were internally financed with cash flow from operations and cash on hand. As of March 31, 2009, the Company had a cash balance of $5.1 million and a working capital deficit of $109.8 million.

Cash Flows. Net cash provided by operating activities was $8.8 million for the three months ended March 31, 2009, as compared to $22.8 million for the same period in 2008. The decrease of $14.0 million was primarily due to lower natural gas production volumes and lower crude oil and natural gas prices, partially offset by lower operating expenses.

Net cash used in investing activities was $15.0 million during the three months ended March 31, 2009, versus $33.8 million in the first three months of 2008 due to decreased capital expenditures partially offset by lower property sales.

Cash flows used in financing activities during the first three months of 2009 were $2.0 million, compared to cash provided by financing activities of $6.9 million during the first three months of 2008 primarily due to the net drawdown on the Credit Facility of $10 million in the first quarter of 2008.

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. The borrowing base under the Credit Facility was redetermined by the syndication group to be $115 million effective October 31, 2007.

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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 250 basis points on the lower end of the range and by 500 basis points on the higher end of the range; the range of the add-on to the alternative base rate was increased by 250 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 500 basis points on the lower end of the range and by 750 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 terms of the Credit Facility contain numerous covenants and restrictions. Currently, the Company is in default of a covenant which requires that it 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 both December 31, 2008 and March 31, 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 report of independent registered accounting firm included a going concern explanatory paragraph expressing substantial doubt about the Company s ability to continue as a going concern.

The Lenders were informed of the defaults under these covenants. 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. On April 13, 2009, the Lenders notified us that as of the effective date of 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, and we do not currently have sufficient cash available to repay the shortfall. The borrowing base is determined at the discretion of the Lenders, based primarily on the value of our proved reserves. The value of our proved reserves has been significantly reduced during the last several months due to the precipitous decrease in the prices of oil and natural gas. We are currently in discussions with the Lenders regarding alternative repayment terms, amortization payments from cash flow, obtaining waivers on the current events of default that have been previously disclosed, providing additional security and entering into forbearance agreements. We cannot provide any assurance that our Lenders will agree to any such arrangements. We are also considering other options for repayment, including the sale of strategic and nonstrategic assets and 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, or at all. Our inability to obtain concessions from our Lenders or to execute other alternatives would have a material adverse effect on our results of operations and financial condition. All indebtedness under the Credit Facility at December 31, 2008 and March 31, 2009, $95.0 million, have been classified in current liabilities on the accompanying Consolidated Balance Sheets.

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 our 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 our outstanding borrowings under the Credit Facility, the Company will be required to repay the deficit within a 90-day period.

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. 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 March 31, 2009, the Company is in default of two of these covenants.

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 March 31, 2009 it was 1.19%, 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 May 1, 2009, outstanding borrowing under the Credit Facility totaled $95.0 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 an event of default under our rig note. The remedies available to CIT in the event of default include acceleration of all principal and interest payments. All indebtedness under the rig note, $8.8 million at December 31, 2008 and $8.4 million at March 31, 2009, has been classified in current liabilities on the accompanying Consolidated Balance Sheets as of December 31, 2008 and March 31, 2009.

CIT was notified of the Company s defaults under the covenants of the Credit Facility, and has not responded with a notice of any remedies it may choose to pursue.

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 as provided by SFAS No. 133, Accounting for Derivative Instruments and Certain Hedging Activities, 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 11 contained elsewhere in this report. All other changes in fair value are reported in the statement of comprehensive income as unrealized gains or losses from hedging activities.

Capital Expenditures. Total capital expenditures for this period 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. Drilling and recompletions for subsequent quarters will depend on the availability of capital.

The Company anticipates the 2009 capital spending budget will be primarily used for recompletions and similar work on existing properties, and for lease maintenance costs. 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 the 2009 plan 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.

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

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

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

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

Uncertainties in Estimating Reserves and Future Net Cash Flows. Reserve engineering is a subjective process of estimating the recovery from underground accumulations of oil and natural gas we cannot measure in an exact manner, and the accuracy of any reserve estimate is a function of the quality of 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.

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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 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 March 31, 2009, we had no cushion (i.e., the excess of the ceiling over our capitalized costs). Thus, any decrease in prices affecting the end of subsequent accounting periods, net of the effect of our hedging positions, may require us to record 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. A 10% decrease in prices would have increased our 2009 non-cash impairment expense by approximately $25.9 million or 44%.

Borrowing base for the Credit Facility. The Amended 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 fixed interest rate debt and variable 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 have been informed by the Lenders that $35 million of the outstanding borrowings under the Credit Facility must be repaid within 90 days of April 30, 2009. 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 $95 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 SFAS 133.

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 March 31, 2009 hedge approximately 29% of proved developed natural gas production and 16% 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 March 31, 2009:

	Type	Notional Amount	Floor Price ($ per unit)	Ceiling Price ($ per unit)	Estimated Fair Value Asset (Liability) March 31, 2009 (in thousands)
Natural Gas (mmbtu)					
Apr 2009 Dec 2009	Collar	860,000	$ 7.50	$ 10.45	$ 2,866
Apr 2009 Dec 2009	Collar	530,000	$ 8.00	$ 10.30	2,012
Apr 2009 Dec 2009	Collar	360,000	$ 8.00	$ 13.35	1,367
				Total Natural Gas	6,245
Crude Oil (bbls)					
Apr 2009 Dec 2009	Collar	17,000	$ 70.00	$ 93.55	298
Apr 2009 Dec 2009	Collar	28,000	$ 80.00	$ 111.00	751
Apr 2009 Dec 2009	Collar	34,000	$ 85.00	$ 128.50	1,070
				Total Crude Oil	2,119
					$ 8,364

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 default of two covenants contained in the Credit 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 set-off any amount due to the Company under the derivative agreements against amounts owed to that counterparty as a Lender under the Credit Facility.

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 first quarter of 2009. Based upon that evaluation,

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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 quarter of 2009 that could significantly affect these controls.

Changes in Internal Controls

During the three month period ended March 31, 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. The Lenders under the Credit Facility have informed the Company that the borrowing base will be revised downward effective April 30, 2009 from the present $95 million to $60 million; the deficit must be repaid within 90 days. Also among the remedies available to Lenders under each of these agreements is acceleration of all principal and interest payments. Accordingly, all such debt, including the rig note, has been classified as current in the Consolidated Balance Sheets as of December 31, 2008 and March 31, 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 March 31, 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

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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 March 31, 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 has recognized an estimated settlement for this matter in the amount of $2.1 million, which was charged to the full cost pool in the first 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.

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 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. In the Company s discussions with Shell, Shell has indicated that it is considering filing an arbitration, but has not yet initiated a formal proceeding. Meridian denies that it owes any indemnity under the 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 March 31, 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.

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ITEM 1A. **Risk Factors.**

For a discussion of the Company s risk factors, see Item 1A, Risk Factors , in the Company s Form 10-K for the year ended December 31, 2008. There have been no changes to these risk factors during the quarter ended March 31, 2009.

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.

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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: May 11, 2009	By: /s/ LLOYD V. DELANO Lloyd V. DeLano Chief Accounting Officer, Senior Vice President and Secretary

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