HOUSTON EXPLORATION CO
Form 10-Q
November 08, 2006

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

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

For the quarterly period ended September 30, 2006

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 No. 001-11899

THE HOUSTON EXPLORATION COMPANY
(Exact name of registrant as specified in its charter)

Delaware **(State or Other Jurisdiction of Incorporation or Organization)**	**22-2674487** **(IRS Employer Identification No.)**
1100 Louisiana, Suite 2000 **Houston, Texas** **(Address of Principal Executive Offices)**	**77002-5215** **(Zip Code)**

(713) 830-6800
(Registrant s Telephone Number, including Area Code)

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 is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

Large accelerated filer þ Accelerated filer o Non-accelerated filero

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

As of November 7, 2006, 28,086,954 shares of Common Stock, par value $0.01 per share, were outstanding.

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Forward-Looking Statements

Certain statements in this Quarterly Report on Form 10-Q (Quarterly Report) and the documents we have incorporated by reference into this Quarterly Report, other than purely historical information, including estimates, projections, statements relating to our business plans, strategies, objectives and expected operating results, and the assumptions upon which those statements are based, are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended (the Securities Act), and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act). These forward-looking statements generally may be identified by the words believe, project, expect, anticipate, estimate, intend, str plan, target, pursue, may, will, would, will continue, will likely result, and similar expressions. Forwar statements are based on current expectations and assumptions that are subject to numerous risks and uncertainties which may cause actual results to differ materially from the forward-looking statements. A detailed discussion of these and other risks and uncertainties that could cause actual results and events to differ materially from such forward-looking statements is included in Item 1A. Risk Factors of our Annual Report on Form 10-K for the year ended December 31, 2005, as amended, our Quarterly Reports on Form 10-Q for the three months ended March 31, 2006 and June 30, 2006 and this Quarterly Report, as well as Risk Factors set forth from time to time in our filings with the Securities and Exchange Commission (SEC). We undertake no obligation to update or revise publicly any forward-looking statements, whether as a result of new information, future events or otherwise.

Available Information

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are available free of charge on our Web site at http://www.houstonexploration.com as soon as reasonably practicable after we electronically file such material with, or otherwise furnish it to, the SEC.

Information contained on or connected to our Web site is not incorporated by reference into this Quarterly Report and should not be considered part of this report or any other filing that we make with the SEC.

In this Quarterly Report, unless the context requires otherwise, when we refer to we, us, our and Houston Exploratio we are describing The Houston Exploration Company including our subsidiaries, THEC, LLC and THEC, LP, on a consolidated basis. Also, unless the context requires otherwise, we are reporting historical results as of September 30, 2006 and December 31, 2005, and for the three-month and nine-month periods ended September 30, 2006 and 2005.

If you are not familiar with the natural gas and oil terms used in this Quarterly Report, please refer to the explanations of the terms under the caption Glossary of Natural Gas and Oil Terms included on pages G-1 through G-2 of our Annual Report on Form 10-K for the year ended December 31, 2005, as amended. When we refer to equivalents, we are doing so to compare quantities of oil with quantities of natural gas or to express these different commodities in a common unit. In calculating equivalents, we use a generally recognized standard in which one barrel of oil is equal to six thousand cubic feet of natural gas. Unless otherwise stated, all reserve and production quantities are expressed net to our interests.

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Part I. Financial Information
Item 1. Condensed Consolidated Financial Statements

THE HOUSTON EXPLORATION COMPANY
CONSOLIDATED BALANCE SHEETS
(in thousands, except share data)
(Unaudited)

	September 30, 2006	December 31, 2005
Assets:		
Cash and cash equivalents	$ 18,435	$ 7,979
Accounts receivable	69,229	146,020
Inventories	6,269	2,726
Deferred tax asset	83,265	145,922
Prepayments and other	27,153	19,709
Total current assets	204,351	322,356
Natural gas and oil properties, full cost method		
Unevaluated properties	45,322	107,146
Properties subject to amortization	3,270,984	3,556,755
Other property and equipment	14,782	12,971
	3,331,088	3,676,872
Less: Accumulated depreciation, depletion and amortization	1,852,530	1,658,532
	1,478,558	2,018,340
Designated cash	314,043	
Other non-current assets	16,616	20,928
Total non-current assets	330,659	20,928
Total Assets	$ 2,013,568	$ 2,361,624
Liabilities:		
Accounts payable and accrued expenses	$ 159,475	$ 177,159
Derivative financial instruments	5,251	352,457
Asset retirement obligation		7,265
Total current liabilities	164,726	536,881
Long-term debt and notes	362,000	597,000
Derivative financial instruments	22,324	65,201
Deferred income taxes	456,786	341,302
Asset retirement obligation	40,015	112,406

Other non-current liabilities	11,008	15,696
Total Liabilities	1,056,859	1,668,486
Commitments and Contingencies (see Note 4)		
Stockholders Equity:		
Preferred Stock, $0.01 par value, 5,000,000 shares authorized and no shares issued		
Common Stock, $0.01 par value, 100,000,000 shares authorized and 28,024,434 and 28,980,128 shares issued and outstanding at September 30, 2006 and December 31, 2005, respectively	280	289
Additional paid-in capital	250,380	297,218
Retained earnings	750,513	663,367
Accumulated other comprehensive (loss)	(44,464)	(267,736)
Total Stockholders Equity	956,709	693,138
Total Liabilities and Stockholders Equity	$ 2,013,568	$ 2,361,624

The accompanying notes are an integral part of these consolidated financial statements.

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THE HOUSTON EXPLORATION COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share data)
(Unaudited)

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Revenues:				
Natural gas and oil revenues	$ 132,673	$ 124,997	$ 453,505	$ 466,011
Other	(1,336)	416	1,350	939
Total revenues	131,337	125,413	454,855	466,950
Operating expenses:				
Lease operating	12,208	17,771	52,052	52,263
Severance tax	4,609	4,165	15,598	11,629
Transportation expense	2,546	3,000	8,176	8,759
Asset retirement accretion expense	489	1,313	2,885	3,964
Depreciation, depletion and amortization	52,565	72,702	194,184	215,249
General and administrative, net of amounts capitalized	9,392	10,229	26,703	27,552
Total operating expenses	81,809	109,180	299,598	319,416
Income from operations	49,528	16,233	155,257	147,534
Other (income) expense	(8,302)	(101)	(10,500)	286
Interest expense, net of amounts capitalized	5,180	3,541	20,352	10,171
Income before income taxes	52,650	12,793	145,405	137,077
Provision for income taxes	18,647	4,712	58,259	51,728
Net income	$ 34,003	$ 8,081	$ 87,146	$ 85,349
Earnings per share:				
Net income per share basic	$ 1.22	$ 0.28	$ 3.06	$ 2.98
Net income per share diluted	$ 1.22	$ 0.28	$ 3.06	$ 2.95
Weighted average shares outstanding basic	27,845	28,744	28,458	28,641
Weighted average shares outstanding diluted	27,936	29,120	28,492	28,966

The accompanying notes are an integral part of these consolidated financial statements.

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THE HOUSTON EXPLORATION COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)
(Unaudited)

	Nine Months Ended September 30,	
	2006	**2005**
Operating Activities:		
Net income	$ 87,146	$ 85,349
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	194,184	215,249
Deferred income tax expense	55,792	39,202
Asset retirement accretion expense	2,885	3,964
Stock compensation expense	7,132	3,719
Tax benefit from non-qualified stock options		2,909
Unrealized (gain) loss on derivative instruments	(44,462)	47,324
Debt extinguishment	572	
Changes in operating assets and liabilities:		
Accounts receivable	76,791	(26,192)
Inventories	(3,543)	(1,353)
Prepayments and other	(7,444)	(9,665)
Other non-current assets	3,939	1,817
Accounts payable and accrued expenses	(29,141)	16,930
Other non-current liabilities	(4,688)	4,728
Net cash provided by operating activities	339,163	383,981
Investing Activities:		
Investment in property and equipment	(447,093)	(401,163)
Cash designated for investment	(323,675)	
Withdrawal of designated cash	9,632	
Dispositions and other	721,607	165
Net cash used in investing activities	(39,529)	(400,998)
Financing Activities:		
Proceeds from long-term borrowings	495,000	364,000
Repayments of long-term borrowings	(730,000)	(370,000)
Proceeds from issuance of common stock from exercise of stock options	6,879	13,217
Repurchase of common stock	(61,638)	
Debt issue costs	(199)	
Tax benefit from non-qualified stock options	780	
Net cash provided by (used in) financing activities	(289,178)	7,217
Increase (decrease) in cash and cash equivalents	10,456	(9,800)
Cash and cash equivalents, beginning of period	7,979	18,577

Cash and cash equivalents, end of period	$	18,435	$	8,777
Supplemental Information:				
Non-cash transactions:				
Investments in property and equipment accrued, not paid	$	(11,457)	$	(19,395)
Cash paid during period for:				
Interest	$	19,424	$	12,664
Federal and state income taxes				19,297

The accompanying notes are an integral part of these consolidated financial statements.

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THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

NOTE 1 Summary of Organization and Significant Accounting Policies

Our Business

We are an independent natural gas and oil producer engaged in the exploration, development, exploitation and acquisition of natural gas and oil reserves in North America. We were founded in December 1985 as a Delaware corporation and wholly-owned subsidiary of our then parent company, KeySpan Corporation. We completed our initial public offering in September 1996. Through three separate transactions, the last of which occurred in November 2004, KeySpan completely divested of its ownership in the common stock of our company. At September 30, 2006, we had operations in four producing regions within the United States: South Texas; the Arkoma Basin of Arkansas and Oklahoma; East Texas; and the Uinta and DJ Basins in the Rocky Mountains.

In November 2005, we announced a strategic plan to restructure the company by pursuing the sale of our Gulf of Mexico assets, shifting our operating focus primarily onshore and repurchasing up to $200 million of our outstanding common stock. On March 31, 2006, we completed the sale of the Texas portion of our Gulf of Mexico assets and on June 1, 2006, we completed the sale of substantially all of our Louisiana Gulf of Mexico assets (see Note 6 Acquisitions and Dispositions*).* The sales of these assets had a significant impact on our operating results for both the three- and nine-month periods ended September 30, 2006 and on the comparability of those results both quarter-over-quarter and period-over period.

On June 12, 2006, we received an unsolicited proposal from JANA Partners LLC, a hedge fund, to acquire our company for $62 per share. According to its public filings, JANA Partners beneficially owned approximately 12.3% of our outstanding common stock as of the date of the proposal. On June 26, 2006, we announced our Board of Directors determination that the unsolicited proposal made by JANA Partners was not in the best interest of our shareholders and that Lehman Brothers Inc. had been engaged to assist us in exploring a broad range of strategic alternatives to further enhance shareholder value. These alternatives may complement or replace the continued execution of our existing business plan and include, but are not limited to, a recapitalization of our company either through additional share repurchases or a special dividend; operating partnerships and / or strategic alliances; and the sale or merger of the company. As of the date of this Quarterly Report, this strategic review is ongoing.

Principles of Consolidation

Our consolidated financial statements include our accounts and the accounts of our wholly-owned subsidiaries. All significant inter-company balances and transactions have been eliminated.

Interim Financial Statements

Our balance sheet at September 30, 2006, and the statements of operations and cash flows for the periods indicated herein have been prepared without audit, pursuant to the rules and regulations of the SEC. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States (GAAP) have been condensed or omitted, although we believe that the disclosures contained herein are adequate to make the information presented not misleading. Our balance sheet at December 31, 2005 is derived from our December 31, 2005 audited financial statements, but does not include all disclosures required by GAAP. The financial statements included herein should be read in conjunction with the Consolidated Financial Statements and Notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2005, as amended.

In the opinion of our management, these financial statements reflect all adjustments necessary for a fair statement of the results for the interim periods on a basis consistent with the annual audited financial statements. All such adjustments are of a normal recurring nature. The results of operations for such interim periods are not necessarily indicative of the results for the full year.

Use of Estimates

The preparation of the consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the dates of the financial statements, as well as the reported amounts of revenues and expenses during the reporting periods. Our most significant estimates are those based on remaining proved natural gas and oil reserves. Specifically,

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
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estimates of proved reserves are key components of our depletion rate for natural gas and oil properties, our unevaluated properties and our full cost ceiling test. In addition, estimates are used in determining taxes, accruals of operating costs and production revenues, asset retirement obligations, fair value and effectiveness of derivative instruments, fair value of stock options and stock-based compensation expense. Because there are numerous uncertainties inherent in the estimation process, actual results could differ materially from these estimates.

Reclassifications

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

Business Segment Information

The Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) 131, Disclosures about Segments of an Enterprise and Related Information, establishes standards for reporting information about operating segments. Operating segments are defined as components of an enterprise that engage in activities from which they may earn revenues and incur expenses, and for which separate financial information is available and regularly evaluated by the chief decision maker for the purpose of allocating resources and assessing performance. Segment reporting is not applicable for us as each of our operating areas has similar economic characteristics and each meets the criteria for aggregation as defined in SFAS 131. All of our operations involve the exploration, development and production of natural gas and oil, and all of our operations are located in the United States. We have a single, company-wide management team that administers all properties as a whole rather than as discrete operating segments. We track only basic operational data by area, and do not maintain comprehensive financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis. Throughout the year, we freely allocate capital resources on a project-by-project basis across our entire asset base to maximize profitability without regard to individual areas or segments.

Revenue Recognition and Gas Imbalances

We use the entitlements method of accounting for the recognition of natural gas and oil revenues. Under this method of accounting, income is recorded based on our net revenue interest in production or nominated deliveries. We recognize and record sales when production is delivered to a specified pipeline point, at which time title and risk of loss are transferred to the purchaser. Our arrangements for the sale of natural gas and oil are evidenced by written contracts with determinable market prices based on published indices. We continually review the creditworthiness of our purchasers in order to reasonably assure the timely collection of our receivables. Historically, we have experienced no material losses on receivables.

We incur production gas volume imbalances in the ordinary course of business. Net deliveries in excess of entitled amounts are recorded as liabilities, and net under-deliveries are reflected as assets. Imbalances are reduced either by subsequent recoupment of over- and under-deliveries or by cash settlement, as required by applicable contracts. Production imbalances are marked-to-market at the end of each month at the lowest of (i) the price in effect at the time of production; (ii) the current market price; or (iii) the contract price, if a contract is applicable.

At September 30, 2006, we had production imbalances representing assets of $1.5 million and liabilities of $2.2 million. At December 31, 2005, we had production imbalances representing assets of $4.9 million and liabilities of $7.2 million, which included imbalances related to our offshore properties that were sold during the first six months of 2006. Our production imbalances at September 30, 2006 relate primarily to certain of our properties in the Arkoma Basin. A significant portion of these imbalances was assumed in connection with our initial acquisition of the properties, and due to the inherent long life and comparatively low production rate of the wells, the imbalances will likely require a long period of time to resolve. Production imbalances are included in the line items other non-current assets and other non-current liabilities on our balance sheet.

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THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

Cash and Cash Equivalents

We consider all highly liquid, short-term investments with original maturities of three months or less to be cash and cash equivalents.

Designated Cash

In connection with the sale of our Gulf of Mexico assets (see Note 6 Acquisitions and Dispositions), we deposited $323.7 million of the $721.6 million in total net cash proceeds received from the sale of these assets with qualified intermediaries for potential reinvestment in like-kind exchange transactions under Section 1031 of the Internal Revenue Code. This cash has been designated for the potential future acquisition of natural gas and oil assets and has been invested in interest-bearing accounts with creditworthy financial institutions. The designated cash is classified on our balance sheet as a non-current asset. During the third quarter of 2006, designated cash of $2.0 million was used to fund qualified investments in natural gas and oil assets. In addition, in September 2006, designated cash of $7.6 million, representing the remaining proceeds from the sale of the Texas offshore assets, was released from escrow, as the 180-day time period for reinvestment under Section 1031 had expired. As a result, our designated cash balance as of September 30, 2006 was reduced to $314.0 million. See Note 4 Commitments and Contingencies *Taxable Gain on Sale of Gulf of Mexico Assets.*

Interest income earned on the designated cash was approximately $4.1 million and $5.7 million, respectively, during the three-month and nine-month periods ended September 30, 2006. Interest income earned is not designated for potential reinvestment in replacement properties and, for both the three-month and nine-month periods ended September 30, 2006, is included in the line item other (income) expense on our statement of operations. During the third quarter of 2006, we reclassified $1.6 million of interest income earned on the designated cash during the first half of 2006 from the line item other revenue to the line item other (income) expense.

Net Income Per Share

Basic net income per share is calculated by dividing net income by the weighted average number of shares of common stock outstanding during the period. Diluted net income per share assumes the conversion of all potentially dilutive securities and is calculated by dividing net income by the sum of the weighted average number of shares of common stock outstanding plus all potentially dilutive securities.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(in thousands, except per share data)			
Numerator:				
Net income	$ 34,003	$ 8,081	$ 87,146	$ 85,349
Denominator:				
Weighted average shares outstanding	27,845	28,744	28,458	28,641
Add: potentially dilutive securities [(1)]	91	376	34	325
Total weighted average shares outstanding and dilutive securities	27,936	29,120	28,492	28,966
Net income per share basic:	$ 1.22	$ 0.28	$ 3.06	$ 2.98
Net income per share diluted:	$ 1.22	$ 0.28	$ 3.06	$ 2.95

(1) Consists of employee stock options and restricted common stock and units.

For the three months ended September 30, 2006 and 2005, the calculation of shares outstanding for net income per share on a diluted basis does not include the effect of outstanding stock options to purchase 583,617 and 407,960 shares, respectively, because the exercise price for these shares was greater than the average market price for the respective periods, which would have an antidilutive effect on net income per share. For the nine months ended September 30, 2006 and 2005, the calculation of shares outstanding for net income per share on a diluted basis does not include the effect of outstanding stock options to purchase 610,862 and 394,513 shares, respectively, because the exercise price for these shares was greater than the average market price for the respective periods, which would have an antidilutive effect on net income per share.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
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Comprehensive Income (Loss)

Comprehensive income (loss) includes net income and certain items that are recorded directly to stockholders equity and classified as other comprehensive income (loss). The table below summarizes comprehensive income (loss) and provides the components of the change in accumulated other comprehensive income (loss) for the three-month and nine-month periods ended September 30, 2006 and 2005.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	**2005**	**2006**	**2005**
	(in thousands)			
Net income	$ 34,003	$ 8,081	$ 87,146	$ 85,349
Other comprehensive income (loss)				
Derivative contracts settled and reclassified, net of tax	19,978	40,192	223,272	65,069
Change in fair value of open derivative contracts, net of tax		(311,008)		(436,007)
Change in accumulated other comprehensive income (loss)	19,978	(270,816)	223,272	(370,938)
Comprehensive income (loss)	$ 53,981	$ (262,735)	$ 310,418	$ (285,589)

Natural Gas and Oil Properties

Full Cost Accounting. We use the full cost method to account for our natural gas and oil properties. Under full cost accounting, all costs directly associated with the acquisition, exploration and development of natural gas and oil reserves are capitalized into a full cost pool. These capitalized costs include costs of all unevaluated properties, internal general and administrative costs directly related to our acquisition, exploration and development activities and capitalized interest. We amortize these costs using a unit-of-production method. Under this method, we compute the provision for depreciation, depletion and amortization at the end of each quarter by multiplying our total production for such quarter by a depletion rate. The depletion rate is determined by dividing our total unamortized cost base by our net equivalent proved reserves at the beginning of the quarter. Our total unamortized cost base is the sum of our:

§ full cost pool (including assets associated with retirement obligations); plus,

§ estimates for future development costs (excluding liabilities associated with retirement obligations); less,

§ unevaluated properties and their related costs; less,

§ estimates for salvage.

Costs associated with unevaluated properties are excluded from our total unamortized cost base until we have made a determination as to the existence of proved reserves. We review our unevaluated properties at the end of each quarter to determine whether the costs incurred should be reclassified to the full cost pool and, thereby, subject to amortization. Sales and abandonment of natural gas and oil properties, whether or not being amortized currently, are accounted for as adjustments to the full cost pool, with no gain or loss recognized, unless the adjustments would significantly alter the relationship between capitalized costs and proved natural gas and oil reserves. A significant alteration would not ordinarily be expected to occur upon the sale of reserves involving less than 25% of the reserve quantities of a cost center. However, we evaluate each asset sale using both qualitative indicators and quantitative measures to determine whether gain or loss recognition is appropriate.

Under full cost accounting, total capitalized costs (net of accumulated depreciation, depletion and amortization) less related deferred taxes may not exceed an amount equal to the present value of future net revenues from proved reserves, discounted at 10% per annum, plus the lower of cost or fair value of unevaluated properties, plus estimated salvage value less income tax effects (the ceiling limitation). We perform a test of this ceiling limitation at the end of each quarter. If our total capitalized costs (net of accumulated depreciation, depletion and amortization) less related deferred taxes are greater than the ceiling limitation, a writedown or impairment of the full cost pool is required. A writedown of the carrying value of the full cost pool is a non-cash charge that reduces earnings and impacts stockholders equity in the period of occurrence and typically results in lower depreciation, depletion and amortization expense in future periods. Once incurred, a writedown is not reversible at a later date.

The ceiling test is calculated using natural gas and oil prices in effect as of the balance sheet date, as adjusted for basis or location differentials as of the balance sheet date and held constant over the life of the reserves (net wellhead prices). If

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

applicable, these net wellhead prices would be further adjusted to include the effects of any fixed price arrangements for the sale of natural gas and oil. Historically, we have used derivative financial instruments to hedge against the volatility of natural gas prices. If our derivative contracts qualify and if they are designated as cash flow hedges under SFAS 133, Accounting for Derivative Instruments and Hedging Activities, then in accordance with SEC guidelines, we include estimated future cash flows from our hedging program in our ceiling test calculation. Since our derivative contracts ceased to qualify as cash flow hedges during the first quarter of 2006, our ceiling test calculation at September 30, 2006 did not include the future cash flows from our hedging program. In addition, subsequent to the adoption of SFAS 143, Accounting for Asset Retirement Obligations, the future cash outflows associated with settling asset retirement obligations (ARO) are excluded from the computation of the discounted present value of future net revenues for the purposes of the ceiling test calculation.

In calculating our ceiling test at September 30, 2006, we estimated that, using an average net wellhead price of $3.68 per Mcf, the carrying value of our full cost pool exceeded the ceiling limitation by approximately $307.1 million (after tax). However, subsequent to September 30, 2006 and prior to filing this Quarterly Report, the market price for natural gas increased such that, using an average net wellhead price of $5.98 per Mcf on November 1, 2006, no writedown was required.

Unevaluated Properties. The costs associated with unevaluated properties are not initially included in the amortization base and relate to unproved leasehold acreage, wells and production facilities in progress and wells pending determination, together with capitalized interest costs for these projects. Unevaluated leasehold costs are transferred to the amortization base with the costs of drilling the related well once a determination has been made or upon expiration of a lease. Costs of seismic data are allocated to various unproved leaseholds and transferred to the amortization base with the associated leasehold costs on a specific project basis. Costs associated with wells in progress and completed wells that have yet to be evaluated are transferred to the amortization base once a determination is made whether or not proved reserves can be assigned to the property. Costs of dry holes are transferred to the amortization base immediately upon determination that the well is unsuccessful.

All items classified as unevaluated property are assessed on a quarterly basis for possible impairment or reduction in value. Where practical, our assessment is performed on a property-by-property basis and includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling activity and results; economic viability; and assignment of proved reserves. We estimate that substantially all of these costs will be evaluated within a four-year period. In connection with the completion of the sale of substantially all of our Gulf of Mexico assets during the first half of 2006, unevaluated properties were reduced by approximately $75.8 million.

General and Administrative Costs and Expenses

Under the full cost method of accounting, we capitalize only those internal general and administrative costs that are directly associated with our acquisition, exploration and development activities, such as salaries, benefits and incentive compensation for geological and geophysical employees and other specifically identifiable non-payroll costs. These capitalized general and administrative costs do not include costs related to production operations, general corporate overhead or other activities not directly attributable to our acquisition, exploration and development efforts. For the three months ended September 30, 2006 and 2005, we capitalized internal general and administrative costs directly associated with our acquisition, exploration and development activities of $4.7 million and $4.2 million, respectively. For the nine months ended September 30, 2006 and 2005, we capitalized internal general and administrative costs of $15.6 million and $12.3 million, respectively.

We receive reimbursement for administrative and overhead expenses incurred on behalf of other working interest owners on properties we operate. These reimbursements totaled $0.5 million for each of the three-month periods ended September 30, 2006 and 2005, and $1.7 million and $1.6 million, respectively, during corresponding nine-month periods then ended. These reimbursements were allocated as reductions to general and administrative expenses incurred. Generally, we do not receive any excess of reimbursements or fees over the costs incurred;

however, if we did, we would credit the excess to the full cost pool to be recognized through lower cost amortization as production occurs.

Capitalization of Interest

We capitalize interest only on investments in unevaluated properties and projects for which exploration or development activity is in progress. Interest is capitalized during the period of time that these properties and projects are classified as

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unevaluated properties and not subject to depreciation, depletion and amortization. See Note 1 Summary of Organization and Significant Accounting Policies *Natural Gas and Oil Properties Unevaluated Properties* for a discussion of unevaluated properties and our assessment process. For the three months ended September 30, 2006 and 2005, capitalized interest totaled $1.0 million and $2.4 million, respectively. For the nine months ended September 30, 2006 and 2005, capitalized interest totaled $3.6 million and $6.8 million, respectively.

Asset Retirement Obligations

The following table describes changes in our ARO liability during each of the nine-month periods ended September 30, 2006 and 2005. The ARO liability in the table below includes amounts classified as both current and long-term at the end of the respective periods.

	Nine Months Ended September 30,	
	2006	**2005**
	(in thousands)	
ARO liability at January 1,	$ 119,671	$ 91,746
Accretion expense	2,885	3,964
Liabilities incurred drilling	5,307	5,496
Liabilities incurred assets acquired	603	169
Liabilities settled assets abandoned		(32)
Liabilities settled assets sold	(88,375)	(937)
Changes in estimates	(76)	798
ARO liability at September 30,	$ 40,015	$ 101,204

Derivative Instruments and Hedging Activities

To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we have historically utilized derivative instruments to hedge future sales prices on a significant portion of our natural gas production. Our derivative instruments are not held for trading purposes. Our hedging policy allows us to implement a wide variety of hedging strategies, including swaps, collars and options. We generally execute derivative contracts with significant, creditworthy financial institutions. Although our hedging program is intended to protect a portion of our cash flows from downward price movements, certain hedging strategies, specifically the use of swaps and collars, may also limit our ability to realize the full benefit of future price increases, as in recent years. In addition, because our derivative instruments are typically indexed to the New York Mercantile Exchange (NYMEX) price, as opposed to the index price where the gas is actually sold, our hedging strategy may not fully protect our cash flows when there are significant price differentials between the NYMEX price and index price at the point of sale, as was the case during the second half of 2005 and the first quarter of 2006 due to the residual impact of Hurricanes Katrina and Rita.

At inception, all of our existing derivative contracts qualified for hedge accounting and were designated as cash flow hedges. Under hedge accounting, derivative contracts designated as cash flow hedges are recorded on the balance sheet as either an asset or liability at fair market value and changes in fair market value (representing unrealized gains or losses) are deferred in accumulated other comprehensive income. Gains and losses are reclassified from accumulated other comprehensive income to the income statement as a component of natural gas and oil revenues in the period when sale of the related production occurs. The portion of the derivative instrument that is ineffective as a hedge, if any, is recorded directly to the income statement and is included as a component of natural gas and oil revenues. For us, ineffectiveness typically results from changes at the end of the current period in the price differentials between the index price of the derivative contract, which typically is a NYMEX price, and the index price for the point of sale for the cash flow that is being hedged.

Under SFAS 133, we are required to assess the effectiveness of all our derivative contracts at inception and at least every three months. If our derivative contracts cease to be effective as cash flow hedges, they would no longer qualify for hedge accounting and mark-to-market accounting would then be utilized. Gains or losses deferred in accumulated other comprehensive income are fixed at the time they cease to qualify for hedge accounting and remain deferred in accumulated other comprehensive income until the related production occurs, at which time these gains or losses are reclassified to income. Subsequent changes in the fair market value of the derivative contracts (representing unrealized gains or losses) are recognized in income as a component of natural gas and oil revenues.

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During the fourth quarter of 2005, the portion of our hedged production allocated to the Houston Ship Channel index failed to qualify for hedge accounting due to a loss of correlation with the NYMEX price caused primarily by the impact of Hurricanes Katrina and Rita. During the first quarter of 2006, the portion of our hedged production allocated to the Arkoma index failed to qualify for hedge accounting due to a loss of correlation with the NYMEX price caused in part by the residual effects of the hurricanes, as well as an increase in the natural gas supply in the mid-continent region associated with a mild winter and pipeline expansions in the region. Finally, in February 2006 in connection with our entry into a definitive purchase and sale agreement to sell the Texas portion of our Gulf of Mexico assets (see Note 6 Acquisitions and Dispositions *Sale of Texas Gulf of Mexico Assets*), the remaining portion of our open derivative contracts ceased to qualify for hedge accounting. As a result, subsequent to February 2006, mark-to-market accounting applies to all of our open derivative contracts, and changes in the fair market value of these open contracts are recognized in income as either a gain or loss and included as a component of natural gas and oil revenues.

In connection with the completion of the divestiture of our Gulf of Mexico assets on June 1, 2006, we were required under our revolving credit facility to liquidate a portion of our 2006 hedge position. In order to comply with this requirement, in June 2006, we liquidated and settled open contracts covering 60,000 MMBtu per day of hedged production for each of the months July through December 2006. The cost to liquidate and settle these contracts was approximately $14.3 million. In addition, on August 4, 2006, we liquidated and settled open derivative contracts representing 20,000 MMBtu per day of hedged production for each of the months September and October 2006. The cost to liquidate and settle these contracts was approximately $0.9 million. After liquidating these contracts, our weighted average open derivative position for the fourth quarter of 2006 decreased from 250,000 MMBtu per day to 183,260 MMBtu per day, which is approximately 82% of our expected equivalent natural gas and oil production for the same period.

At September 30, 2006, an unrealized loss of $44.5 million, net of tax, remains deferred in accumulated other comprehensive income. This loss represents the fixed value of our remaining open derivative contracts deferred in accumulated other comprehensive income at the time they ceased to qualify for hedge accounting. All of these deferred losses will be reclassified and recognized in future earnings at the time when sale of the related natural gas production occurs. Over the next 12-month period, we expect to reclassify from accumulated other comprehensive income to earnings a net loss of $34.3 million, net of tax, leaving $10.2 million to be recognized thereafter.

Accounting for Stock Options and Restricted Stock

On January 1, 2003, we adopted the fair value expense recognition provisions of SFAS 123, Accounting for Stock-Based Compensation, as amended by SFAS 148, Accounting for Stock Based Compensation Transition and Disclosure using the prospective method as defined by SFAS 148. Accordingly, we recognized compensation expense for all stock options granted subsequent to January 1, 2003. On January 1, 2006, we adopted SFAS 123(R), Share-Based Payment. Accordingly, we now recognize compensation expense for all stock options, including the unvested portion of all grants made prior to our initial adoption of SFAS 123 on January 1, 2003. Prior period amounts have not been restated. Prior to adopting SFAS 123 in January 2003 and SFAS 123(R) in January 2006, we accounted for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board (APB) Opinion 25, Accounting for Stock Issued to Employees, and related interpretations.

If we had accounted for all stock options using the fair value method as recommended in SFAS 123 and 123(R), compensation expense would have had the following pro forma effect on our net income and earnings per share for the three-month and nine-month periods ended September 30, 2005:

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	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2005
	(in thousands, except per share data)	
Net income as reported	$ 8,081	$ 85,349
Add: Stock-based compensation expense included in net income, net of tax	831	1,705
Less: Stock-based compensation expense determined using fair value method, net of tax	(1,183)	(2,769)
Net income pro forma	$ 7,729	$ 84,285
Net income per share basic as reported	$ 0.28	$ 2.98
Net income per share diluted as reported	0.28	2.95
Net income per share basic pro forma	$ 0.27	$ 2.94
Net income per share diluted pro forma	0.27	2.91

The weighted average fair value of options granted and valuation assumptions used in the Black-Scholes option-pricing model during the nine-month periods ended September 30, 2006 and 2005 are as follows:

	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Weighted average fair value of options granted	$13.96	$21.05
Assumptions:		
Risk-free interest rate	4.8%	4.0%
Expected years until exercise	4	5
Expected stock volatility	23.4%	34.0%
Expected dividends		

The Black-Scholes option pricing model requires the input of certain subjective assumptions, including the expected stock price volatility and expected life of the option. For the risk-free interest rate, we utilize United States treasury bills with constant maturities that correspond to the option s expected life. The expected life is based on historical exercise activity over the previous ten-year period. The expected volatility is based on historical volatility and measured using the average closing price of our stock over a 48-month period. We believe historical volatility is the most accurate measure of future volatility of our common stock. Our expected rate of forfeitures is estimated at 5% and is based on historical forfeiture rates over the previous ten-year period.

The following table provides the detail of stock compensation expense incurred during each of the three-month and nine-month periods ended September 30, 2006 and 2005:

	Three Months Ended	Nine Months Ended

	September 30,		September 30,	
	2006	2005	2006	2005
	(in thousands)			
Options	$ 1,467	$ 1,185	$ 4,716	$ 2,768
Restricted stock/units	793	512	2,416	951
Stock compensation expense, gross	2,260	1,697	7,132	3,719
Amounts capitalized	(811)	(581)	(2,559)	(1,250)
Stock compensation expense, net of amounts capitalized	$ 1,449	$ 1,116	$ 4,573	$ 2,469

Amounts capitalized are categorized as leasehold costs and included as a component of our natural gas and oil property balance or full cost pool. Amounts expensed are included as a component of general and administrative expense. At September 30, 2006, our unrecognized stock compensation expense related to unvested stock options to be recognized over a weighted average two and one half-year period was approximately $7.4 million. At September 30, 2006, our unrecognized compensation expense related to restricted stock and units and expected to be recognized over a weighted

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average two and one half-year period totaled $6.6 million. These amounts are classified as unearned compensation and included as a component of additional paid-in capital

Stock Plans. We have four stock option plans (together, our Stock Plans): (i) the 1996 Stock Option Plan, which was adopted at the completion of our initial public offering in September 1996, and amended and approved by our stockholders in 1997; (ii) the 1999 Non-Qualified Stock Option Plan adopted by our Board of Directors in October 1999; (iii) the 2002 Long-Term Incentive Plan adopted in January 2002, approved by our stockholders in May 2002 and amended by our Board in October 2003; and (iv) the 2004 Long-Term Incentive Plan, approved by our stockholders in June 2004 and amended and restated by our Board in January 2006. All our employees, directors, consultants and advisors are eligible to participate in our Stock Plans, except that executive officers are not eligible to participate in the 1999 plan. The 1996, 2002 and 2004 plans allow for the granting of both incentive stock options and non-qualified stock options, and the 2002 and 2004 plans allow for the granting of restricted stock. Upon shareholder approval of the 2004 plan, all remaining options available for grant under the 2002, 1999 and 1996 plans were cancelled, and 1,500,000 shares were authorized for awards under the 2004 plan. At September 30, 2006, we had 656,731 shares authorized and available for award under the 2004 plan.

Stock Options. Options granted under our Stock Plans expire 10 years from the grant date and vest in equal annual increments over either a five-year or three-year vesting period, except that options granted to directors vest immediately upon grant. In general, stock options become fully vested upon the occurrence of a change of control, unless an award agreement provides otherwise. All stock options have an exercise price equal to the closing price of our common stock as reported on the NYSE on the date of grant. After the amendment and restatement of the 2004 plan in January 2006, non-employee directors are no longer eligible to receive stock options and instead will receive an annual grant of restricted stock, the number of shares of which is determined by dividing $100,000 by the closing price of our common stock on the date of our Annual Meeting of Stockholders.

Common stock issued through the exercise of non-qualified stock options will result in a tax deduction for us which is equal to the taxable gain recognized by the optionee. Generally, we will not receive an income tax deduction for incentive stock options. For financial reporting purposes, the tax effect of this deduction is accounted for as a credit to additional paid-in-capital rather than as a reduction of income tax expense. Prior to the adoption of SFAS 123(R) on January 1, 2006, we presented tax benefits resulting from stock-based compensation as a cash flow from operating activities within our consolidated statements of cash flows. SFAS 123(R) requires excess tax benefits to be presented as a cash flow from financing activities. For the three-month and nine-month periods ended September 30, 2006, we recognized excess tax benefits of $0.6 million and $0.8 million, respectively. For the corresponding three-month and nine-month periods ended September 30, 2005, we recognized excess tax benefits of $1.0 million and $2.9 million, respectively.

The following table below summarizes the activity with respect to stock options for the nine months ended September 30, 2006:

	Shares Underlying Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value[(1)]
	(shares)	($/share)	(Years)	($ in thousands)
Options outstanding January 1, 2006	1,696,610	$ 39.85	7.8	$ 21,971
Granted	41,920	53.12		85
Exercised	(195,199)	35.23		5,052

Forfeited	(60,504)	36.82		
Options outstanding September 30, 2006	1,482,827	$ 40.96	4.2	$ 21,041
Options exercisable September 30, 2006	607,479	$ 32.03	2.5	$ 14,045

(1) The intrinsic value of an option is the amount by which the current market value of the underlying stock exceeds the exercise price of the option, or the market price at the end of the period less the exercise price. At September 30, 2006 and December 31, 2005, the closing price per share of our common stock on the NYSE was $55.15 and $52.80, respectively.

The total intrinsic value of options exercised during the three-month and nine-month periods ended September 30, 2006 was $2.8 million and $5.1 million, respectively. For the corresponding three-month and nine-month periods ended

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September 30, 2005, the total intrinsic value of options exercised during these periods was $3.8 million and $11.3 million, respectively.

Restricted Stock. Restricted stock may be granted and issued to executive officers, employees and non-employee directors as a component of each recipient s annual compensation, and vesting is generally dependent upon continued service to our company. Restricted stock carries voting and dividend rights; however, the sale or transfer of the shares is restricted. Generally, restricted shares vest and become freely transferable at the end of the vesting period, which is either five years or three years from the date of grant. In general, accelerated vesting will occur upon the occurrence of certain events, including a change of control (as defined by the plan), unless an award agreement provides otherwise, and in the case of non-employee directors, termination as a director by reason of death, disability or retirement. Restricted stock awards are valued at the closing price of our common stock on the date of grant.

The following table below summarizes the activity with respect to restricted stock and units for the nine months ended September 30, 2006:

	Restricted Stock and Units[1] (shares)	Weighted Average Grant Date Fair Value ($/share)	Aggregate Intrinsic Value[2] ($ in thousands)
Unvested restricted stock January 1, 2006	171,214	$ 56.23	$ 9,040
Granted	25,016	54.16	1,380
Vested	(803)	58.88	
Forfeited	(7,225)	58.88	
Unvested restricted stock September 30, 2006	188,202	$ 55.84	$ 10,379

(1) Includes 52,501 units granted in July 2005 pursuant to a retention bonus plan for certain employees at an average price of $58.76 per unit, of which 50% vest 18 months following the grant date with the remaining 50% to vest 36 months following the grant date.

Restricted units will convert to shares of common stock at the end of the vesting period. At September 30, 2006, 45,276 units under the retention bonus plan were unvested and outstanding.

(2) For unvested shares of restricted stock, the intrinsic value is calculated using the closing price of our common stock at the end of the period. For restricted shares that vested during the period, the intrinsic value is calculated using the closing price of our common stock on the vesting date. At September 30, 2006 and December 31, 2005, the closing price per share of our common stock on the NYSE was $55.15 and $52.80, respectively.

Recent Accounting Pronouncements

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. SFAS 157 defines fair value, establishes a framework for measuring fair value and requires enhanced disclosures regarding fair value measurements. SFAS 157 does not add any new fair value measurements, but it does change current practice and is intended to increase consistency and comparability in such measurement. The provisions of SFAS 157 are effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. We are currently evaluating the impact of adopting SFAS 157 on our financial statements and assessing early adoption which is permitted and would occur as of the first quarter of fiscal 2007, or in our case, January 1, 2007.

In September 2006, the FASB issued SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans. SFAS 158 amends SFAS 87, Employers Accounting for Pensions, SFAS 88, Employers Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits, SFAS 106, Employers Accounting for Postretirement Benefits Other Than Pensions, and SFAS 132 (revised 2003), Employers Disclosures about Pensions and Other Postretirement Benefits. SFAS No. 158 requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability on its balance sheet and to recognize changes in the funded status in the year in which the changes occur through comprehensive income. SFAS 158 also requires employers to measure the funded status of a plan as of the date of its year-end balance sheet, with limited exceptions. Employers with publicly traded equity securities are required to initially recognize the funded status of a defined benefit postretirement plan and to provide the required disclosures as of the end of the fiscal year ending after December 15, 2006; however, the requirement to measure plan assets and benefit obligations as of the date of the employer s fiscal year-end financial position is effective for fiscal years ending after December 15, 2008. We plan to adopt all requirements of SFAS 158 on December 31, 2006, except for the funded status measurement date

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requirement which will be adopted on December 31, 2008, as allowed under SFAS 158. We are currently evaluating the impact the adoption of SFAS 158 may have on our financial statements.

In September 2006, the SEC issued Staff Accounting Bulletin No.108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements (SAB 108). SAB 108 provides guidance on how to evaluate prior period financial statement misstatements for purposes of assessing their materiality in the current period. If the prior period effect is material to the current period, then the prior period is required to be corrected. Correcting prior year financial statements would not require an amendment of prior year financial statements, but such corrections would be made the next time the company files the prior year financial statements. Upon adoption, SAB 108 allows a one-time transitional cumulative effect adjustment to retained earnings for corrections of prior period misstatements required under this statement. SAB 108 is effective for fiscal years beginning after November 15, 2006. The adoption of SAB 108 is not expected to be material to our consolidated financial statements.

In July 2006, the FASB issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement 109 (FIN 48), which clarifies the accounting for uncertainty in tax positions taken or expected to be taken in a tax return, including issues relating to financial statement recognition and measurement. FIN 48 provides that the tax effects from an uncertain tax position can be recognized in the financial statements only if the position is more-likely-than-not to be sustained if the position were to be challenged by a taxing authority. The assessment of the tax position is based solely on the technical merits of the position, without regard to the likelihood that the tax position may be challenged. If an uncertain tax position meets the more-likely-than-not threshold, the largest amount of tax benefit that is more than 50 percent likely to be recognized upon ultimate settlement with the taxing authority, is recorded. The provisions of FIN 48 are effective for fiscal years beginning after December 15, 2006, with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. Consistent with the requirements of FIN 48, we will adopt FIN 48 on January 1, 2007. We are currently evaluating the impact of adopting FIN 48 on our financial statements.

NOTE 2 Long-Term Debt and Notes

	September 30, 2006	December 31, 2005
	(in thousands)	
Senior Debt:		
Revolving credit facility, due November 30, 2010	$ 187,000	$ 422,000
Subordinated Debt:		
7% senior subordinated notes, due June 15, 2013	175,000	175,000
Total long-term debt and notes	$ 362,000	$ 597,000

The carrying amount of borrowings outstanding under our revolving credit facility approximates fair value as the interest rates are tied to current market rates. At September 30, 2006, the quoted market value of our $175 million of 7% senior subordinated notes was 96.0% of the $175 million carrying value, or $168 million. At December 31, 2005, the quoted market value of our $175 million of 7% senior subordinated notes was 95.4% of the $175 million carrying value, or $167 million.

Revolving Credit Facility

We maintain a revolving credit facility with a syndicate of lenders led by Wachovia Bank, National Association, as issuing bank and administrative agent, The Bank of Nova Scotia and Bank of America as co-syndication agents and BNP Paribas and Comerica Bank as co-documentation agents. The facility provides us with a commitment of $750 million, which may be increased at our request and with prior approval from the required lenders to a maximum of $850 million. Amounts available for borrowing under the credit facility are limited to a borrowing base that is redetermined semi-annually on April 1st and October 1st. Up to $60 million of our borrowing base is available for the issuance of letters of credit. Effective June 1, 2006, in connection with the completion of the sale of the Louisiana portion of our Gulf of Mexico assets, our borrowing base of $550 million was reduced to $500 million. In connection with this reduction, we incurred debt extinguishment expense of $0.6 million during the second quarter of 2006 relating to the write-off of a portion of our debt issuance costs. Effective October 1, 2006, our borrowing base was redetermined and remained at $500 million. We expect our current $500 million borrowing base to remain in effect until the next scheduled semi-annual redetermination on April 1, 2007. Outstanding borrowings under the revolving credit facility are secured by substantially all of our natural gas and oil assets as well as certain other assets and rank senior in right of payment to our $175 million of 7% senior subordinated notes. The

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facility matures on November 30, 2010. At September 30, 2006, we had $187 million in outstanding borrowings under the credit facility and $0.3 million in outstanding letter of credit obligations.

Interest is payable on borrowings under our revolving credit facility as follows:

§ on base rate loans, at a fluctuating rate, or base rate, equal to the sum of (a) the greater of the Federal funds rate plus 0.5% or Wachovia s prime rate plus (b) a variable margin between 0.00% and 0.50%, depending on the amount of borrowings outstanding under the credit facility, or

§ on fixed rate loans, a fixed rate equal to the sum of (a) a quoted LIBOR rate divided by one minus the average maximum rate during the interest period set for certain reserves of member banks of the Federal Reserve System in Dallas, Texas, plus (b) a variable margin between 1.00% and 1.75%, depending on the amount of borrowings outstanding under the credit facility.

Interest is payable on base-rate loans on the last day of each calendar quarter. Interest on fixed-rate loans is generally payable at maturity or at least every 90 days if the term of the loan exceeds three months. In addition to interest, we must pay a quarterly commitment fee of between 0.30% and 0.50% per annum on the unused portion of the borrowing base.

Our revolving credit facility contains customary financial and other covenants that place restrictions and limits on, among other things, the incurrence of debt, guarantees, liens, leases and certain investments. The credit facility also restricts and limits our ability to pay cash dividends, purchase or redeem our stock, and sell or encumber our assets.

Financial covenants require us to, among other things:

§ maintain a ratio of earnings before interest, taxes, depreciation, depletion and amortization (EBITDA) to cash interest payments of at least 3.00 to 1.00;

§ maintain a ratio of total debt to EBITDA of not more than 3.50 to 1.00; and

§ hedge no more than 85% of our expected production during any calendar year.

At September 30, 2006 and December 31, 2005, we were in compliance with all covenants under our revolving credit facility.

Senior Subordinated Notes

On June 10, 2003, we issued $175 million of 7% senior subordinated notes due June 15, 2013. The notes bear interest at a rate of 7% per annum with interest payable semi-annually on June 15 and December 15. We may redeem the notes at our option, in whole or in part, at any time on or after June 15, 2008, at a price equal to 100% of the principal amount plus accrued and unpaid interest, if any, plus a specified premium that decreases yearly from 3.5% in 2008 to 0% in 2011 and thereafter. The notes are general unsecured obligations and rank subordinate in right of payment to all of our existing and future senior debt, including the revolving credit facility, and will rank senior or equal in right of payment to all existing and future subordinated indebtedness.

The indenture governing the notes contains covenants that, among other things, restrict or limit:

§ incurrence of additional indebtedness and issuance of preferred stock;

§ repayment of certain other indebtedness;

§ payment of dividends or certain other distributions;

§ investments and repurchases of equity;

§ use of proceeds of assets sales;

§ transactions with affiliates;

§ creation, incurrence or assumption of liens;

§ merger or consolidation and sales or other dispositions of all or substantially all of our assets;

§ entering into agreements that restrict the ability of our subsidiaries to make certain distributions or payments; and

§ guarantees by our subsidiaries of certain indebtedness.

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In addition, upon the occurrence of a change of control (as defined in the indenture), we will be required to offer to purchase the notes at a purchase price equal to 101% of the aggregate principal amount, plus accrued and unpaid interest and liquidated damages, if any.

At September 30, 2006 and December 31, 2005, we were in compliance with all covenants under the indenture governing the notes.

NOTE 3 Stockholders Equity

Stock Repurchases

On November 4, 2005, and in conjunction with the divestiture of all of our Gulf of Mexico assets, our Board of Directors approved discretionary repurchases from time to time over twelve months of up to $200 million in company stock. In May 2006, we initiated our share repurchases, and during May and June 2006, we repurchased a total of 1,176,500 shares, or approximately 4% of our outstanding common stock, in the open market at a weighted average price of $52.39 per share for a total cost of approximately $61.6 million. All repurchases were paid for in cash and funded with cash on hand or borrowings under our revolving credit facility. All repurchased shares were retired. No share repurchases were made during the third quarter of 2006.

NOTE 4 Commitments and Contingencies

Taxable Gain on Sale of Gulf of Mexico Assets

We have established a structure permitting reinvestment of the remaining $314.0 million of cash proceeds from the sale of the Louisiana portion of our Gulf of Mexico assets in a manner that qualifies as a like-kind exchange under Section 1031 of the Internal Revenue Code (see Note 6 Acquisitions and Dispositions). As of the date of this Quarterly Report, we do not expect any qualified reinvestments in natural gas and oil properties to be completed by November 27, 2006 (180 days after the closing of the sale of our Louisiana Gulf of Mexico assets), the deadline under Section 1031. Therefore, we expect to withdraw the remaining escrowed sales proceeds from designated cash and reclassify the amount withdrawn as cash and to recognize a taxable gain of approximately $250 million to $260 million during the fourth quarter of 2006. We estimate that the incremental income tax liability associated with this gain will be approximately $90 million to $95 million. However, any cash payment for estimated income tax that is required during the fourth quarter of 2006 will be based on our total net taxable income, of which any gain from the sale of our Gulf of Mexico assets will be a component. We estimate that, after considering our available net operating losses and alternative minimum tax credits, our total net tax liability will be reduced to approximately $35 million to $40 million. At September 30, 2006, this estimated tax liability is included as a component of our deferred tax liability.

Legal Proceedings

On June 22, 2006, the City of Monroe Employees Retirement System filed a purported class action lawsuit in the District Court of Harris County, Texas, on behalf of itself and all of the company s other public shareholders, against the company and its directors. The plaintiff alleges that the defendants breached their fiduciary duties of loyalty and due care to the class in connection with our response to an unsolicited proposal by JANA Partners LLC to purchase the company. The plaintiff subsequently amended its petition as a derivative claim and requested that the court order the defendants to comply with their fiduciary duties, respond in good faith to potential offers, and establish a committee of independent directors to evaluate strategic alternatives and take decisive steps to maximize shareholder value. The plaintiff also seeks to invalidate our shareholder rights plan or require the defendants to rescind or redeem such plan. Finally, the plaintiff seeks compensatory and punitive damages, as well as attorneys and experts fees. In October 2006, the judge denied the defendants motion to abate or special exceptions. Although this ruling allows the plaintiff s claim to survive beyond the pleadings stage, it has no bearing on the merits of the case. We believe this lawsuit is without merit, and we intend to vigorously defend against it. Although it is too soon to predict the outcome of this lawsuit or the time to resolution, we do not believe that it will have a material adverse effect on our financial position, results of operations or cash flows.

In addition to the foregoing, we are involved from time to time in various other claims and lawsuits incidental to our business. In the opinion of management, the ultimate liability, if any, associated with these matters is not expected to have a material adverse effect on our financial position, results of operations or cash flows.

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Operating Leases

We have entered into non-cancelable operating lease agreements in the ordinary course of our business activities. These leases include those for our office space at 1100 Louisiana Street in Houston, Texas, and at 700 17th Street in Denver, Colorado, together with various types of office equipment (copiers and fax machines). The terms of these agreements have various expiration dates from 2006 through 2009. Future minimum lease payments for the remainder of 2006 and each of the subsequent four years from 2007 through 2010 are $0.5 million, $1.9 million, $1.9 million, $1.1 million and $0.9 million, respectively.

Letters of Credit

We had $0.3 million in letters of credit outstanding at each of September 30, 2006 and at December 31, 2005.

Drilling Contracts

During 2006, we entered into three long-term contracts for the exclusive use of drilling rigs for periods of greater than or equal to 12 months. These include a one-year contract for a drilling rig in East Texas; a two-year contract for a rig in the Uinta Basin; and a one-year contract for a rig in South Texas. Under these contracts, we are obligated for up to an estimated $11.6 million in fees for use of the rigs during the remaining terms of the contracts.

Seismic Contracts

During October 2006, we entered into an agreement to acquire seismic data covering various acreage positions in Colorado. Under the terms of the agreement, we are obligated for up to an estimated $3.0 million in fees.

Supplemental Executive Retirement Plan

Effective January 1, 2006, we adopted a Supplemental Executive Retirement Plan, which was amended and restated as of July 25, 2006 (SERP), to provide retirement benefits to certain management level or other highly compensated employees. The SERP is an unfunded, non-tax qualified defined benefit pension plan. Initial participation in the SERP is currently limited to our executive officers. Participants in the SERP will be entitled to a monthly retirement benefit payable for life. The amount of this monthly retirement benefit is equal to 2.5% times final average compensation times years of service with the company (not to exceed 20 years), reduced by an annuity (offset) based on a hypothetical account that is credited with 6% of the participant s annual base salary and bonus paid each year and investment returns as defined in the SERP. Participants are fully vested in their benefits after five years of plan participation or age 65, whichever is earlier. If a vested participant retires prior to age 65, then the monthly retirement benefit as described above (before reduction for the offset) will be reduced by 5% for each year that retirement precedes age 65. In the event a participant is terminated for cause before becoming vested in his or her benefits, all benefits under the SERP will be forfeited. In general, benefits will be paid when the participant retires from the company or beginning at age 65. However, in the event of a change of control (as defined in the plan), the benefit will be paid as a lump-sum if a participant s employment is terminated by us without cause or the participant resigns for good reason within two years following a change of control. All benefits become fully vested upon a change of control whether or not a participant s employment is terminated. During the three-month and nine-month periods ended September 30, 2006, we recognized $0.3 million and $0.9 million, respectively, in costs associated with the SERP.

NOTE 5 Related Party Transactions

Employment Agreements with Executives

On January 18, 2006, we entered into an employment agreement with Robert T. Ray in connection with Mr. Ray s appointment as Senior Vice President and Chief Financial Officer of our company and, on March 27, 2006, we entered into

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an employment agreement with Carolyn M. Campbell in connection with Ms. Campbell s appointment as Senior Vice President and General Counsel of our company.

In addition to the agreements with Mr. Ray and Ms. Campbell, we have employment agreements in place with all of our other executive officers. These agreements have an initial term of three years, which is automatically extended each year for an additional year on the anniversary of the effective date, unless either party gives notice to the contrary within 90 days prior to such anniversary of the effective date. Executive officers receive annual salary and bonus payments pursuant to their employment agreements which are subject to review each year by our Compensation Committee. Payment of the bonus is based on achievement of certain performance goals established each year by our Compensation Committee. In addition, executive officers are eligible to participate in our stock compensation, deferred compensation and supplemental executive retirement plans.

If we terminate an executive without cause (as defined in the agreement), or if the executive terminates his or her employment with us for good reason (as defined in the agreement, which includes the occurrence of certain events following a change in control), we are obligated to pay the executive a lump-sum severance payment equal to 2.99 times his or her then current annual rate of total compensation, and to continue certain medical and insurance benefits for a specified time period. The agreements further provide that if any payments made to the executive, whether or not under the agreement, would result in an excise tax being imposed on the executive under Section 4999 of the Internal Revenue Code, we will make each of the executives whole on a net after-tax basis.

We may terminate any employment agreement for cause without financial obligation (other than payment of any accrued obligations). Each executive may terminate his or her agreement at any time and for any reason upon at least 30 days prior written notice. In the event the executive s employment is terminated by us without cause or upon death or disability, or if the executive terminates his or her employment with us for good reason, any unvested shares of restricted stock, unvested options or similar deferred compensation will automatically vest and any other conditions to such awards will be deemed satisfied.

The terms of Mr. Ray s and Ms. Campbell s employment agreements are consistent with the general terms described above. Further, Mr. Ray s agreement provides for an initial annual base salary of $315,000 and an annual incentive bonus equal to 55% of his base salary upon the achievement of pre-established performance goals. Ms. Campbell s agreement provides for an initial annual base salary of $275,000 and an annual incentive bonus equal to 55% of her salary upon the achievement of pre-established performance goals. In addition, Mr. Ray received a signing bonus in the amount of $85,000, together with 7,500 restricted shares of our common stock and options to purchase 20,000 shares of our common stock at $53.72 per share. Ms. Campbell received 5,000 restricted shares of our common stock and options to purchase 15,000 shares of our common stock at an exercise price of $50.41 per share. The agreements provide for an automobile allowance of $700 per month and reimbursement of certain business expenses and require us to provide certain disability and life insurance. If we terminate Mr. Ray or Ms. Campbell without cause, or if either terminates their employment with us for good reason, we are obligated to pay each a lump sum severance payment as described above. Based on initial compensation levels, Mr. Ray s lump sum payment would equal approximately $1.5 million and Ms. Campbell s would equal approximately $1.3 million.

NOTE 6 Acquisitions and Dispositions

Sale of Texas Gulf of Mexico Assets

On March 31, 2006, we completed the sale of the Texas portion of our Gulf of Mexico assets. Pursuant to the purchase and sale agreement dated February 28, 2006 between us, as seller, and various partnerships affiliated with Merit Energy Company, as buyer, the gross sale price was $220 million. The net cash proceeds received from the sale of these assets totaled approximately $190.8 million after various customary closing items, including the adjustment for operations related to the properties after January 1, 2006, the effective date of the transactions. Of the total net proceeds, approximately $140.1 million was received for assets acquired by various partnerships affiliated with Merit Energy Company. In addition, approximately $43.1 million and $7.6 million were received from Hydro Gulf of Mexico, L.L.C. and Nippon Oil Exploration U.S.A. Ltd., respectively, pursuant to the exercise of their preferential rights to acquire certain working interests offered for sale. The Texas portion of our Gulf of Mexico assets accounted for approximately 18% of our 2005 production and represented an estimated 58.5 Bcfe, or 7% of our total proved reserves at December 31, 2005. Of the $190.8 million in net cash proceeds received from the sale of our Texas Gulf of Mexico assets, we used $158 million to repay and reduce outstanding borrowings under our revolving credit facility, deposited $9.5 million with a qualified

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intermediary for potential reinvestment in like-kind exchange transactions under Section 1031 of the Internal Revenue Code, and used substantially all of the $23.3 million balance for working capital purposes. In accordance with full cost accounting, no gain or loss was recognized on the sale. The net proceeds of $190.8 million were recorded as a reduction to the full cost pool.

Sale of Louisiana Gulf of Mexico Assets

On June 1, 2006, we completed the sale of substantially all of our Louisiana Gulf of Mexico assets for a gross sale price of $590 million. The sale of a substantial majority of these assets to various partnerships affiliated with Merit Energy Company was completed on May 31, 2006 pursuant to a purchase and sale agreement dated April 7, 2006, and the sale of certain working interests to Nippon Oil Exploration U.S.A. Ltd. and Chevron USA Inc. was completed on June 1, 2006 pursuant to the exercise of preferential purchase rights. The aggregate net cash proceeds received from the sale of these assets totaled approximately $530.8 million after customary closing items, including the preliminary adjustment for operations related to the properties after January 1, 2006, the effective date of the transactions. Of the total net proceeds, approximately $510.2 million was received from various partnerships affiliated with Merit Energy Company, and approximately $16.6 million and $4.0 million was received from Nippon Oil Exploration U.S.A. Ltd. and Chevron USA Inc., respectively.

At December 31, 2005, proved reserves associated with these assets were estimated at 186.1 Bcfe, and production associated with these assets accounted for approximately 22% of our 2005 production and 27% of our production during the first six months of 2006. The sale transactions did not include 18 Louisiana offshore blocks retained by us. Of these 18 blocks, 16 are undeveloped and two had exploratory wells in progress at the time of the sale.

Of the $530.8 million in net cash proceeds received from the sale of the Louisiana portion of our Gulf of Mexico assets, $314.2 million was deposited directly with qualified intermediaries for potential reinvestment in like-kind exchange transactions under Section 1031 of the Internal Revenue Code, and substantially all of the $216.6 million balance, associated with properties sold outside the like-kind exchange arrangement, was used to reduce outstanding borrowings under our revolving credit facility. In accordance with full cost accounting, no gain or loss was recognized on the sale. The net proceeds of $530.8 million were recorded as a reduction to the full cost pool.

The sale of certain of our Gulf of Mexico properties accelerated the payment of a net profits interest to the predecessor owner of properties acquired by us in October 2003, for which we paid approximately $21.0 million during August 2006. The payment was accounted for as a purchase price adjustment in connection with the original acquisition of the properties and recorded as an addition to natural gas and oil properties.

East Texas Acquisition

On April 25, 2006, we completed the acquisition of certain interests in natural gas and oil producing properties, together with acreage located in the Willow Springs Field of Gregg County, Texas, from Samson Lone Star Limited Partnership. The net purchase price of $21.3 million was paid in cash and funded in part by cash on hand of $19.1 million and borrowings under our bank credit facility of $2.2 million. The $22.0 million gross purchase price was reduced by $0.7 million for various customary closing items, including an adjustment for operations related to the properties after the January 1, 2006 effective date of the transaction. The properties cover approximately 4,237 gross (3,579 net) acres, are adjacent to our existing operations in the Willow Springs Field and include interests in 28 producing wells with an average working interest of 80%. Based on internal estimates, total proved reserves associated with the interests acquired were approximately 16.2 Bcfe as of January 1, 2006.

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Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations
The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. This section should be read in conjunction with our Consolidated Financial Statements and the accompanying notes included elsewhere in this Quarterly Report on Form 10-Q, as well as our Annual Report on Form 10-K, as amended, for the year ended December 31, 2005.
Statements in our discussion may be forward-looking. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause actual results, including future production, revenues and expenses, to differ materially from our expectations. See Forward-Looking Statements at the beginning of this Quarterly Report, Item 1A. Risk Factors in our Annual Report on Form 10-K, as amended, for the year ended December 31, 2005, and Item 1A. Risk Factors in Part II of our Quarterly Reports on Form 10-Q for the periods ended March 31, 2006 and June 30, 2006 and this Quarterly Report for additional discussion of risks affecting our business.
Overview of Our Business
We are an independent natural gas and oil producer engaged in the exploration, development, exploitation and acquisition of natural gas and oil reserves in North America. We were founded in December 1985 as a Delaware corporation and wholly-owned subsidiary of our then parent company, KeySpan Corporation. We completed our initial public offering in September 1996. Through three separate transactions, the last of which occurred in November 2004, KeySpan completely divested of its ownership in the common stock of the company.
At September 30, 2006, we had operations in four producing regions within the United States: South Texas; the Arkoma Basin of Arkansas and Oklahoma; East Texas; and the Uinta and DJ Basins in the Rocky Mountains. On June 1, 2006, we completed the sale of substantially all of our Gulf of Mexico assets (see Note 6 Acquisitions and Dispositions).
Our total net proved reserves as of December 31, 2005 were 861 billion cubic feet equivalent, or Bcfe, with onshore reserves totaling 616 Bcfe. Our reserves are evaluated on an annual basis in a report prepared by independent petroleum engineers. Approximately 64% of our proved reserves at December 31, 2005 were classified as proved developed.
We derive our revenues from the sale of natural gas and oil that is produced from our natural gas and oil properties. Revenues are a function of the volume produced and the prevailing market price at the time of sale. Because natural gas accounts for approximately 95% of our production, the price of natural gas is the primary factor affecting our revenues. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we have historically utilized derivative instruments to hedge future sales prices on a significant portion of our natural gas production. Our use of derivative instruments prevented us from realizing the full benefit of the strong natural gas price environment during the first nine months of 2006 and in each of the preceding three years, and may continue to do so in future periods. Our natural gas revenues may experience significant volatility in future periods as all of our open derivative contracts ceased to qualify for hedge accounting during the first quarter of 2006 (see Note 1 Summary of Organization and Significant Accounting Policies *Derivative Instruments and Hedging Activities*).
Segment reporting is not applicable for us, as all of our assets are based in North America and each of our operating areas has similar economic characteristics and each meets the criteria for aggregation as defined in SFAS 131, Disclosures about Segments of an Enterprise and Related Information.
Strategic Restructuring Plan
In November 2005, we announced our strategic restructuring plan, the primary purpose of which is to enhance shareholder value by becoming a pure onshore operator. We believe the strategic shift toward focusing our operations onshore will leverage our strength of developing complex, tight or low permeability natural gas reservoirs and provide flexibility to expand both in our present core onshore areas and other tight gas basins, positioning us to benefit from opportunities that may arise in connection with acquisition or consolidation transactions. We also anticipate that focusing our efforts onshore will provide a more stable and predictable production and reserve growth profile, improve our overall reserve-to production ratio, and result in lower finding and development costs. We believe our existing onshore portfolio offers a multi-year inventory of drilling opportunities, and that we can continue to realize the benefits of scale by operating the majority of our properties and maintaining a high working interest.

We have completed significant steps towards our original restructuring objectives, including the sale of substantially all of our Gulf of Mexico assets for net cash proceeds of $721.6 million; the repurchase and retirement of 1,176,500 shares, or approximately 4% of our outstanding common stock, for approximately $61.6 million; and the liquidation and settlement of a portion of our open derivative contracts for natural gas for approximately $15.2 million.

On June 12, 2006, we received an unsolicited proposal from JANA Partners LLC, a hedge fund, to acquire our company for $62 per share. According to its public filings, JANA Partners beneficially owned approximately 12.3% of our outstanding common stock as of the date of the proposal. On June 26, 2006, we announced our Board of Directors determination that the unsolicited proposal made by JANA Partners was not in the best interest of our shareholders and that we had engaged Lehman Brothers Inc. to assist us in evaluating strategic alternatives.

We are continuing to explore a broad range of strategic alternatives to further enhance shareholder value. These alternatives may complement or replace the continued execution of our existing business plan and include, but are not limited to, a recapitalization of our company either through additional share repurchases or a special dividend; operating partnerships and / or strategic alliances; and the sale or merger of the company. In conjunction with the ongoing exploration of strategic alternatives, we will continue to focus on the redeployment of the net sales proceeds of our offshore assets into a variety of opportunities, each aimed at enhancing shareholder value. These opportunities may include onshore acquisitions, additional debt repayments and discretionary stock repurchases.

Disposition of Gulf of Mexico Assets. On March 31, 2006, we completed the sale of the Texas portion of our Gulf of Mexico assets. The $220 million gross sale price was adjusted by $29.2 million for various customary closing items, including the preliminary adjustment for operations related to the properties after January 1, 2006, the effective date of the transaction. Of the $190.8 million in net cash proceeds, approximately $140.1 million was received for assets sold to various partnerships affiliated with Merit Energy Company. In addition, approximately $43.1 million and $7.6 million were received from Hydro Gulf of Mexico, L.L.C. and Nippon Oil Exploration U.S.A. Ltd., respectively, pursuant to the exercise of their preferential purchase rights. We used $158 million of the net cash proceeds received from the sale of these assets to repay and reduce outstanding borrowings under our revolving credit facility; deposited $9.5 million of the proceeds with a qualified intermediary for potential reinvestment in like-kind exchange transactions under Section 1031 of the Internal Revenue Code; and used substantially all of the $23.3 million balance for working capital purposes. During the third quarter of 2006, $7.6 million of funds escrowed in connection with the sale of the Texas portion of our offshore assets, representing that portion of such funds that had not been reinvested within the 180-day time period under Section 1031, was released from escrow and reclassified as cash.

On June 1, 2006, we completed the sale of substantially all of our Louisiana Gulf of Mexico assets for a gross purchase price of $590 million. The sale of a substantial majority of these assets to various partnerships affiliated with Merit Energy Company was completed on May 31, 2006 pursuant to a purchase and sale agreement dated April 7, 2006, and the sale of certain working interests to Nippon Oil Exploration U.S.A. Ltd. and Chevron USA Inc. was completed on June 1, 2006 pursuant to the exercise of preferential purchase rights. The aggregate net cash proceeds received from the sale of these assets totaled approximately $530.8 million after customary closing items, including the preliminary adjustment for operations related to the properties after January 1, 2006, the effective date of the transactions. Of the total net proceeds, approximately $510.2 million was received for assets acquired by the Merit affiliates, and approximately $16.6 million and $4.0 million was received from Nippon Oil Exploration U.S.A. Ltd. and Chevron USA Inc., respectively.

Of the $530.8 million in net cash proceeds received from the sale of the Louisiana portion of our Gulf of Mexico assets, $314.2 million was deposited directly with qualified intermediaries for potential reinvestment in like-kind exchange transactions under Section 1031 of the Internal Revenue Code, and substantially all of the $216.6 million balance, associated with properties sold outside the like-kind exchange arrangement, was used to reduce outstanding borrowings under our revolving credit facility.

As of the date of this Quarterly Report, and due to the November 27, 2006 expiration of the 180-day reinvestment period under Section 1031, we expect that all of the previously escrowed sales proceeds will be withdrawn from designated cash and reclassified as cash, during the fourth quarter which will result in a taxable gain to us of approximately $250 million to $260 million. We estimate that, after considering our available net operating losses and alternative minimum tax credits, our total net tax liability will be reduced to approximately $35 million to $40 million. At September 30, 2006, this estimated tax liability is included as a component of our deferred tax liability. In addition, the recognition of a taxable gain on the sale of the offshore assets may have an impact on our ceiling test calculation in future periods.

The sale of certain of our Gulf of Mexico properties accelerated the payment of a net profits interest to the predecessor owner of properties acquired by us in October 2003 and, on August 1, 2006, we paid approximately $21.0 million in connection with the net profits interest, which we funded with borrowings under our revolving credit facility.

The sale transactions did not include 18 Louisiana offshore blocks, which we retained. Of these 18 blocks, 16 are undeveloped and two had exploratory wells in progress at the time of the sale.

Redeployment of Net Sales Proceeds. Subject to our ongoing exploration of strategic alternatives, we intend to pursue a balanced and disciplined approach to the redeployment of net proceeds from the sale of our Gulf of Mexico assets. Specifically, we intend to pursue a variety of reinvestment alternatives, each designed to facilitate our continued growth and further enhance shareholder value. These opportunities may include additional share repurchases, a special dividend, operating partnerships, strategic alliances, the development of our existing onshore assets, the pursuit of additional opportunities onshore and the repayment of debt, as well as the sale or merger of the company. We expect to be disciplined in our approach, targeting only those opportunities that deliver clear strategic and financial benefits as measured by, among other things, our internal rate of return and accretion metrics. In the event we do not apply the net proceeds from the sales of our offshore assets, within 360 days following each such sale, to acquire natural gas and oil assets, make capital expenditures or permanently reduce senior debt, we may be required by the indenture governing our senior subordinated notes to offer to repurchase or redeem a portion of these notes.

Given that our offshore assets accounted for 27% of our production during the first six months of 2006 and 40% of our production during 2005 and represented approximately 245 Bcfe, or 28% of our proved reserves, at December 31, 2005, our operating cash flows have declined to below prior year levels following the sale of these assets. There can be no assurance that we will elect to or be able to replace this sold production with the acquisition of new properties, as market conditions, the availability of suitable properties, our evaluation of other strategic alternatives, inherent acquisition risks and other uncertainties may not allow for the reinvestment of all of the proceeds on attractive terms. Our ability to identify onshore properties that warrant investment and consummate their acquisition should position our onshore business for growth. However, our desire or ability to pursue any such opportunities is subject to a number of factors, many of which are beyond our control. Accordingly, we cannot ensure that any such opportunities will be available to us, nor can we predict with any degree of certainty the impact of any such opportunities or any strategic alternatives on our financial condition, results of operations or cash flows.

Hedging Strategy. In connection with the June 1, 2006 completion of the divestiture of substantially all our Gulf of Mexico assets, we were required under our revolving credit facility to liquidate a portion of our 2006 hedge position. In order to comply with this requirement, in June 2006, we liquidated and settled open contracts representing 60,000 MMBtu per day of hedged production for each of the months July through December 2006. The cost to liquidate and settle these contracts was approximately $14.3 million. In addition, on August 4, 2006, we liquidated and settled open derivative contracts representing 20,000 MMBtu per day of hedged production for each of the months September and October 2006. The cost to liquidate and settle these contracts was approximately $0.9 million. After liquidating these contracts, our weighted average open derivative position for the fourth quarter of 2006 decreased from 190,000 MMBtu per day to 183,260 MMBtu per day, which is approximately 82% of expected equivalent natural gas and oil production for the three-month period ending December 31, 2006. We currently have open derivative positions covering 30,000 MMBtu per day for 2007 and 20,000 MMBtu per day for 2008. Based on our current projections, we anticipate that the 30,000 MMBtu per day for 2007 will approximate 12% of our expected equivalent production rate for 2007. We continue to evaluate opportunities to hedge both our production and basis differential exposure and may elect to do so if market conditions warrant. In addition, if we believe market conditions are favorable, we may elect to liquidate additional derivative contract positions in the future.

Acquisitions

On April 25, 2006, we completed the acquisition of certain interests in natural gas and oil producing properties and acreage in the Willow Springs Field of Gregg County, located in East Texas, from Samson Lone Star Limited Partnership. The $22 million cash purchase price was reduced by $0.7 million to $21.3 million for various customary closing items, including an adjustment for operations related to the properties after the effective date of the transaction, January 1, 2006. The properties cover approximately 4,237 gross (3,579 net) acres, are adjacent to our existing operations in the Willow Springs Field and include interests in 28 producing wells with an average working interest of 80%. Based on internal estimates, total proved reserves associated with the interests acquired were 16.2 Bcfe as of January 1, 2006. The acquisition was funded with cash on hand of $19.1 million and borrowings under our revolving credit facility of $2.2 million.

Critical Accounting Estimates and Significant Accounting Policies

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of our financial statements requires us to make assumptions and prepare estimates that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities and revenues and expenses. We base our estimates on historical experience and various other assumptions that we believe are reasonable; however, actual results may differ. We evaluate our assumptions and estimates on a regular basis and discuss the development and disclosure process with our Audit Committee. Estimates of proved reserves are key components of our most significant financial estimates involving unevaluated properties, depreciation, depletion and amortization and our full cost ceiling limitation. In addition, estimates are used to accrue production revenues and operating expenses, drilling costs, federal and state taxes, the fair value of derivative contracts, including the calculation of ineffectiveness, and the fair value of our stock options. There has been no change in our critical accounting policies and use of estimates since our Annual Report for the year ended December 31, 2005, as amended.

Recent Accounting Pronouncements

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. SFAS 157 defines fair value, establishes a framework for measuring fair value under GAAP and requires enhanced disclosures regarding fair value measurements. SFAS 157 does not add any new fair value measurements, but it does change current practice and is intended to increase consistency and comparability in such measurement. The provisions of SFAS 157 are effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. We are currently evaluating the impact of adopting SFAS 157 on our financial statements and assessing early adoption as of the first quarter of fiscal 2007, or in our case, January 1, 2007.

In September 2006, the FASB issued SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans. SFAS 158 amends SFAS 87, Employers Accounting for Pensions, SFAS 88, Employers Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits, SFAS 106, Employers Accounting for Postretirement Benefits Other Than Pensions, and SFAS 132 (revised 2003), Employers Disclosures about Pensions and Other Postretirement Benefits. SFAS No. 158 requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability on its balance sheet and to recognize changes in the funded status in the year in which the changes occur through comprehensive income. SFAS 158 also requires employers to measure the funded status of a plan as of the date of its year-end balance sheet, with limited exceptions. Employers with publicly traded equity securities are required to initially recognize the funded status of a defined benefit postretirement plan and to provide the required disclosures as of the end of the fiscal year ending after December 15, 2006; however, the requirement to measure plan assets and benefit obligations as of the date of the employer s fiscal year-end financial position is effective for fiscal years ending after December 15, 2008. We plan to adopt all requirements of SFAS 158 on December 31, 2006, except for the funded status measurement date requirement which will be adopted on December 31, 2008, as allowed under SFAS 158. We are currently evaluating the impact the adoption of SFAS 158 may have on our financial statements.

In September 2006, the SEC issued Staff Accounting Bulletin No.108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements (SAB 108). SAB 108 provides guidance on how to evaluate prior period financial statement misstatements for purposes of assessing their materiality in the current period. If the prior period effect is material to the current period, then the prior period is required to be corrected. Correcting prior year financial statements would not require an amendment of prior year financial statements, but such corrections would be made the next time the company files the prior year financial statements. Upon adoption, SAB 108 allows a one-time transitional cumulative effect adjustment to retained earnings for corrections of prior period misstatements required under this statement. SAB 108 is effective for fiscal years beginning after November 15, 2006. The adoption of SAB 108 is not expected to be material to our consolidated financial statements.

In July 2006, the FASB issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement 109 (FIN 48) , which clarifies the accounting for uncertainty in tax positions taken or expected to be taken in a tax return, including issues relating to financial statement recognition and measurement. FIN 48 provides that the tax effects from an uncertain tax position can be recognized in the financial statements only if the position is more-likely-than-not to be sustained if the position were to be challenged by a taxing authority. The assessment of the tax position is based solely on the technical merits of the position, without regard to the likelihood that the tax position may be challenged. If an uncertain tax position meets the more-likely-than-not threshold, the largest amount of tax benefit that is more than 50 percent likely to be recognized upon ultimate settlement with the taxing authority, is recorded. The provisions of FIN 48 are effective for fiscal years beginning after December 15, 2006, with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. Consistent with the requirements of FIN 48, we will adopt FIN 48 on January 1, 2007. We are currently evaluating the impact of adopting FIN 48 on our financial statements

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Overview of Results for the Third Quarter of 2006

Following the sale of substantially all of our Gulf of Mexico assets during the first half of 2006, our third quarter results were driven almost entirely by our production, exploration and development activities within our onshore areas. Our total onshore production of 204 MMcfe per day during the third quarter of 2006 was 10% higher than the 185 MMcfe per day produced by our onshore assets during the third quarter of 2005. This increase was realized despite pipeline capacity constraints that continued in both the Rockies and Arkoma regions. Natural gas prices continued to decline during the third quarter of 2006 from the record highs set during the third and fourth quarters of 2005 after Hurricanes Katrina and Rita and reached lows not seen since November 2002 due, in part, to historically high levels of U.S. natural gas storage. As a result of this decline in gas prices, we recognized significant unrealized gains on our derivative positions, and our cash losses on the settlement of derivative contracts narrowed considerably from the first and second quarters of 2006 and from the third and fourth quarters of 2005. Along with this decline in natural gas prices, we began to see some stabilization in rig rates and other service costs; however, the lower prices also caused our depreciation, depletion and amortization rate to increase for the third quarter of 2006.

During the third quarter of 2006:

§ We generated $34.0 million in net income, including $22.6 million ($14.6 million after tax) of unrealized gains on open derivative contracts in connection with mark-to-market accounting, compared to $8.1 million in net income during the third quarter of 2005, including unrealized losses from hedging activities of $45.9 million ($29.7 million after tax);

§ We produced approximately 19 Bcfe and our average total production rate was 204 MMcfe per day, a decrease of approximately 10 Bcfe and 104 MMcfe per day, respectively, from the third quarter of 2005, which decrease is primarily a result of the sale of substantially all of our offshore assets, offset in part by an increase in production from our onshore assets;

§ We increased production from our onshore properties by 10%, to 204 MMcfe per day, from 185 MMcfe per day during the third quarter of 2005;

§ We generated $85.8 million in cash flows from operating activities, a decrease of 32% from the $126.8 million during the third quarter of 2005;

§ We invested $142.7 million in natural gas and oil properties;

§ We increased net borrowings under our revolving credit facility by $87 million and used these borrowings to fund our exploration and development activities;

§ We drilled 110 wells, of which 100, or 91%, were successful, including 43 in the Rockies, 28 in South Texas, 20 in Arkoma, and 9 in East Texas;

§ We withdrew $9.6 million of the $323.7 million in offshore sales proceeds we had previously deposited with qualified intermediaries and designated for potential reinvestment in like-kind exchange transactions under Section 1031 of the Internal Revenue Code, of which $2.0 million was invested in qualified natural gas and oil assets and the balance, or $7.6 million which remained from the sale of the Texas portion of our offshore assets, was released from escrow due to the expiration of the 180-day reinvestment period;

§ We paid $0.9 million to liquidate and settle derivative contracts covering 20,000 MMBtu per day for each of the months September and October 2006; and

§ We continued our review of strategic alternatives that was announced by our Board of Directors on June 26, 2006.

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Operating and Financial Results for the Three Month and Nine Month Periods Ended September 30, 2006 Compared to the Three Month and Nine Month Periods Ended September 30, 2005.

The impact of Hurricanes Katrina and Rita in the third quarter of 2005 and the sale of substantially all of our Gulf of Mexico assets during the first half of 2006 had a significant impact on the comparability of our operating results for both the three- and nine-month periods ended September 30, 2006 to the corresponding three- and nine-month periods ended September 30, 2005. Specifically, our operating results for the nine-month period ended September 30, 2006 include production, revenues and expenses relating to our Texas Gulf of Mexico properties until the completion of their sale on March 31, 2006 and our Louisiana Gulf of Mexico properties until the completion of their sale on June 1, 2006.

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2006	2005	Change	%	2006	2005	Change	%
	(in thousands, except prices and percentages)							
Operating revenues	$131,337	$125,413	$ 5,924	5%	$454,855	$466,950	$(12,095)	-3%
Operating expenses	81,809	109,180	(27,371)	-25%	299,598	319,416	(19,818)	-6%
Income from operations	49,528	16,233	33,295	205%	155,257	147,534	7,723	5%
Net income	34,003	8,081	25,922	321%	87,146	85,349	1,797	2%
Production:								
Natural gas (MMcf)	18,081	26,217	(8,136)	-31%	64,348	81,014	(16,666)	-21%
Oil (MBbls)	117	360	(243)	-68%	722	1,172	(450)	-38%
Total (MMcfe) (1)	18,783	28,377	(9,594)	-34%	68,680	88,046	(19,366)	-22%
Average daily production (MMcfe/d)	204	308	(104)	-34%	252	323	(71)	-22%
Average Sales Prices:								
Natural Gas (per Mcf) unhedged	$ 5.85	$ 8.15	$ (2.30)	-28%	$ 6.75	$ 6.90	$ (0.15)	-2%
Natural Gas (per Mcf) realized (2)	5.70	5.78	(0.08)	-1%	5.69	5.65	0.04	1%
Natural Gas (per Mcf) all-in (3)	6.95	4.03	2.92	72%	6.39	5.07	1.32	26%
Oil (per Bbl) realized	59.86	54.08	5.78	11%	59.04	47.27	11.77	25%

(1) MMcfe is defined as one million cubic feet equivalent of natural gas, determined using the ratio of six MMcf of natural gas to one MBbl of crude oil, condensate or natural gas liquids.

(2) Includes gains and losses realized on derivative contracts settled during the period.

(3) Includes both the effect of gains and losses realized on derivative contracts settled during the period as well as unrealized gains and losses recognized pursuant to accounting under SFAS 133.

Production Volume

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2006	**2005**	**Change**	**%**	**2006**	**2005**	**Change**	**%**
	(in thousands, except percentages)							
Natural Gas Production (MMcf):								
Onshore	18,081	16,879	1,202	7%	53,261	50,681	2,580	5%
Offshore		9,338	(9,338)	-100%	11,087	30,333	(19,246)	-63%
Total natural gas	18,081	26,217	(8,136)	-31%	64,348	81,014	(16,666)	-21%
Oil (MBbls):								
Onshore	108	24	84	350%	289	69	220	319%
Offshore	9	336	(327)	-97%	433	1,103	(670)	-61%
Total oil	117	360	(243)	-68%	722	1,172	(450)	-38%
Natural Gas Equivalent (MMcfe):								
Onshore	18,729	17,023	1,706	10%	54,995	51,095	3,900	8%
Offshore	54	11,354	(11,300)	-100%	13,685	36,951	(23,266)	-63%
Total equivalents	18,783	28,377	(9,594)	-34%	68,680	88,046	(19,366)	-22%

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The following table provides a comparison of average daily production by area:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2006	2005	Change	%	2006	2005	Change	%
	(MMcfe per day, except percentages)				(MMcfe per day, except percentages)			
South Texas	142	127	15	12%	143	134	9	7%
Arkoma	40	46	(6)	-13%	40	43	(3)	-7%
East Texas	12	7	5	71%	11	4	7	175%
Rockies	9	4	5	125%	7	5	2	40%
Other	1	1			1	1		
Total onshore	204	185	19	10%	202	187	15	8%
Offshore		123	(123)	-100%	50	136	(86)	-63%
Total (MMcfe/day)	204	308	(104)	-34%	252	323	(71)	-22%

As a result of the sale of substantially all of our Gulf of Mexico assets during the first half of 2006, our total production volumes were 34% lower during the third quarter of 2006 compared to the third quarter of 2005 and 22% lower for the first nine months of 2006 as compared to the first nine months of 2005.

For both the three-month and nine-month periods ended September 30, 2006, average daily production for our onshore properties increased by 10% and 8%, respectively. In South Texas, production increased 12% quarter-over-quarter and 7% period-over-period, due primarily to the acquisition of properties from Kerr-McGee Oil and Gas Onshore LP and Westport Oil and Gas Company, L.P. in November 2005 and the results of subsequent developmental drilling activity on these properties. In Arkoma, average daily production declined 13% during the third quarter and 7% during the first nine months of 2006, due in part to curtailments during the second and third quarters of 2006 caused by oversupply in the gathering system. In East Texas, production increased by 5 MMcfe per day, or 71%, quarter-over-quarter and by 7 MMcfe per day, or 175%, period-over-period, due to our acquisition of acreage and producing wells during 2005 and 2006, combined with our subsequent development drilling activity, which has resulted in the successful drilling of 21 new wells in 2006. However, our production in this area was curtailed during the second and third quarters of 2006 due to compression and pipeline constraints. In the Rockies, we continued to add production and connect completed wells to sales, as evidenced by our average daily production rates, which increased by 5 MMcfe per day, or 125%, quarter-over-quarter and 2 MMcfe per day, or 40%, period-over-period. However, we also experienced curtailments in Utah during the second and third quarters of 2006 due to compressor issues, high line pressure and fluids in the third party gathering lines that limited production flow.

Commodity Prices and Effects of Hedging

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2006	2005	Change	%	2006	2005	Change	%
Average Natural Gas Prices ($ per Mcf):								
Onshore	$ 5.86	$ 7.75	$ (1.89)	-24%	$ 6.49	$ 6.62	$ (0.13)	-2%
Offshore		8.86	(8.86)	-100%	7.97	7.35	0.62	8%
Total Natural Gas unhedged	5.85	8.15	(2.30)	-28%	6.75	6.90	(0.15)	-2%
Total Natural Gas realized (1)	5.70	5.78	(0.08)	-1%	5.69	5.65	0.04	1%
Total Natural Gas all-in (2)	6.95	4.03	2.92	72%	6.39	5.07	1.32	26%

Average Oil Prices ($ per Bbl):								
Onshore	61.53	46.46	15.07	32%	58.87	51.36	7.51	15%
Offshore	39.89	54.63	(14.74)	-27%	59.15	47.01	12.14	26%
Total Oil	59.86	54.08	5.78	11%	59.04	47.27	11.77	25%

(1) Includes gains and losses realized on derivative contracts settled during the period.

(2) Includes gains and losses realized on derivative contracts settled during the period, as well as unrealized gains and losses recognized pursuant to SFAS 133.

Our average realized price for natural gas, which includes gains and losses realized on derivative contracts settled during the period and excludes unrealized gains and losses on these derivative contracts, was flat both quarter-over-quarter and period-over-period. The decline in the market price for natural gas throughout 2006 has served to narrow the difference

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between our unhedged and realized natural gas prices. Specifically, our net cash losses realized on derivative contracts settled during the period reduced our unhedged prices by only $0.15 per Mcf during the third quarter of 2006, to $5.70 per Mcf, as compared to a reduction of $2.37 per Mcf during the third quarter of 2005, to $5.78 per Mcf. For the first nine months of 2006, net cash losses realized on derivatives settled during the period reduced unhedged prices by $1.06 per Mcf compared to $1.25 per Mcf during the corresponding nine months of 2005.

The following table summarizes the components of our realized and unrealized gains and losses due to derivative contracts for the three-month and nine-month periods ended September 30, 2006 and 2005. All amounts in the following table are shown on a pre-tax basis and are included in our statement of operations on the line item natural gas and oil revenues.

	Three Months Ended September 30,			**Nine Months Ended September 30,**		
	2006	**2005**	**Change**	**2006**	**2005**	**Change**
	(in thousands)					
Gain (Loss) from Hedging Activities						
Cash (loss) realized on contracts settled [1]	$ (2,715)	$ (62,216)	$ 59,501	$ (67,664)	$ (100,726)	$ 33,062
Non-cash unrealized gain (loss):						
Ineffectiveness gain (loss)	7,070	(45,900)	52,970	38,970	(47,324)	86,294
Mark-to-market change in fair value gain (loss)	15,521		15,521	84,307		84,307
Deferred loss prior quarter production shortfalls				(20,600)		(20,600)
Recognition of all deferred losses relating to Gulf of Mexico production sold during period				(58,215)		(58,215)
Total non-cash unrealized gain (loss)	22,591	(45,900)	68,491	44,462	(47,324)	91,786
Total gain (loss) from hedging activities	$ 19,876	$ (108,116)	$ 127,992	$ (23,202)	$ (148,050)	$ 124,848

(1) For the three months ended September 30, 2006, also includes $0.9 million to liquidate and settle contracts covering 20,000 MMBtu per day for each of the months September and October 2006. For the nine months ended September 30,

2006, includes the aforementioned $0.9 million paid during the third quarter of 2006 and $14.3 million paid during the second quarter of 2006 to liquidate and settle contracts covering 60,000 MMBtu per day for each of the months July through December 2006. This 60,000 MMBtu per day liquidiation was made in connection with the completion of the sale of our Gulf of Mexico assets on June 1, 2006 and was required under the terms of our revolving credit facility.

The decline in the market price for natural gas throughout 2006 from the record high levels seen during the fourth quarter of 2005 and the first two months of 2006 caused our cash loss realized from the settlement of derivative contracts to narrow significantly from a loss of $62.2 million during the third quarter of 2005 to a net loss of $2.7 million during the third quarter of 2006 and from a net loss of $100.7 million for the first nine months of 2005 to a net loss of $67.7 million for the first nine months of 2006.

All of the non-cash, unrealized gains and losses shown in the above table result from accounting for derivative instruments under SFAS 133. During the fourth quarter of 2005 and the first quarter of 2006, a portion of our derivative contracts became ineffective as hedges. In addition, in conjunction with our entry into an agreement on February 28, 2006 to sell our Texas Gulf of Mexico assets, the remaining portion of all our open derivative contracts ceased to qualify for hedge accounting. We may continue to experience volatility in our natural gas and oil revenues during future periods as mark-to-market accounting is now utilized for all of our open derivative contracts.

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Natural Gas and Oil Revenues

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2006	2005	Change	%	2006	2005	Change	%
	(in thousands, except percentages)							
Natural Gas Revenues:								
Onshore	$ 105,875	$ 130,894	$ (25,019)	-19%	$ 345,679	$ 335,598	$ 10,081	3%
Offshore	(82)	82,749	(82,831)	-100%	88,404	223,068	(134,664)	-60%
Gain (loss) on settled derivatives	(2,715)	(62,216)	59,501	-96%	(67,664)	(100,726)	33,062	-33%
Unrealized gain (loss) on derivatives	22,591	(45,900)	68,491	-149%	44,462	(47,324)	91,786	-194%
Total natural gas revenues	125,669	105,527	20,142	19%	410,881	410,616	265	%
Oil Revenues:								
Onshore	6,645	1,115	5,530	496%	17,012	3,544	13,468	380%
Offshore	359	18,355	(17,996)	-98%	25,612	51,851	(26,239)	-51%
Total oil revenues	7,004	19,470	(12,466)	-64%	42,624	55,395	(12,771)	-23%
Total natural gas and oil revenues	$ 132,673	$ 124,997	$ 7,676	6%	$ 453,505	$ 466,011	$ (12,506)	-3%

For the three months ended September 30, 2006, natural gas revenues from our onshore properties declined by $25.0 million, or 19%, from levels in the corresponding three months of 2005 due primarily to average unhedged natural gas prices that were 24%, or $1.89 per Mcf, lower quarter-over-quarter. This price related decline was partially offset by a 7% increase in onshore natural gas production volume for the third quarter of 2006. For the nine months ended September 30, 2006, onshore natural gas revenues were $10.1 million, or 3%, higher than the corresponding nine months of 2005 due to a 5% increase in natural gas production, offset in part by a $0.13 per Mcf, or 2%, decrease in price.

Lower natural gas prices during the second and third quarters of 2006 narrowed our net loss on derivatives settled during the period by $59.5 million for the third quarter and by $33.1 million for the first nine months of 2006. These lower natural gas prices, combined with a reduction in the aggregate size of our hedge portfolio, caused our non-cash unrealized gains and losses on open derivative contracts to move from a loss of $45.9 million during the third quarter of 2005 to a gain of $22.6 million during the third quarter of 2006.

The increase in the market price for oil due to geopolitical and other macroeconomic factors, combined with an increase in onshore oil production of 84 MBbls, or 350%, during the third quarter of 2006 and 220 MBbls, or 319%, during the first nine months of 2006, added approximately $5.5 million and $13.5 million, respectively, in oil revenues quarter-over-quarter and period-over-period.

Operating Expenses

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2006	2005	Change	%	2006	2005	Change	%
	($ per MMcfe, except percentages)							
Lease operating expense	$ 0.65	$ 0.63	$ 0.02	3%	$ 0.76	$ 0.59	$ 0.17	29%
Severance tax	0.25	0.15	0.10	67%	0.23	0.13	0.10	77%
Transportation expense	0.14	0.11	0.03	27%	0.12	0.10	0.02	20%
Asset retirement accretion expense	0.03	0.05	(0.02)	-40%	0.04	0.05	(0.01)	-20%
Depreciation, depletion and amortization	2.80	2.56	0.24	9%	2.83	2.44	0.39	16%
General and administrative, net	0.50	0.36	0.14	39%	0.39	0.31	0.08	26%
Total operating expenses per unit of production	$ 4.37	$ 3.86	$ 0.51	13%	$ 4.37	$ 3.62	$ 0.75	21%

Total operating expenses on an absolute dollar basis decreased 25% quarter-over-quarter, from $109.2 million during the third quarter of 2005 to $81.8 million during the third quarter of 2006, and by 6% for the nine month period-over-period, from $319.4 million during the first nine months of 2005 to $299.6 million during the first nine months of 2006, primarily as a result of lower lease operating expense, depreciation, depletion and amortization expense and asset retirement accretion expense following the sale of substantially all of our Gulf of Mexico assets during the first half of 2006.

Despite the above absolute dollar declines, on a unit of production basis, operating expenses increased $0.51 per Mcfe, or 13%, quarter-over-quarter and $0.75 per Mcfe, or 21%, period-over-period.

Per unit expenses were higher for all categories of operating expense, other than asset retirement accretion expense, for both the three-month and the nine-month periods ended September 30, 2006 due to a lower level of production as a direct result of the sale of our offshore producing assets. Also contributing to these higher per unit expenses was the continued upward pressure on service costs, labor, materials, insurance and property taxes resulting from the sustained strength of commodity prices versus historical levels during the first half of 2006.

Lease Operating Expense. The following table summarizes our lease operating expenses on both an absolute dollar and unit of production basis for onshore and offshore properties for the three-month and nine-month periods ended September 30, 2006 and 2005.

	Three Months Ended September 30,				**Nine Months Ended September 30,**			
	2006	**2005**	**Change**	**%**	**2006**	**2005**	**Change**	**%**
	(in thousands, except percentages)							
Onshore	$ 11,984	$ 7,398	$ 4,586	62%	$ 35,162	$ 20,493	$ 14,669	72%
Offshore	224	10,373	(10,149)	-98%	16,890	31,770	(14,880)	-47%
Total	$ 12,208	$ 17,771	$ (5,563)	-31%	$ 52,052	$ 52,263	$ (211)	
Onshore per Mcfe	$ 0.64	$ 0.43	$ 0.21	49%	$ 0.64	$ 0.40	$ 0.24	60%
Offshore per Mcfe		0.91	(0.91)	N/A	1.23	0.86	0.37	43%
Total	0.65	0.63	0.02	3%	0.76	0.59	0.17	29%

On an absolute dollar basis, total lease operating expense decreased by 31% for the third quarter of 2006 as compared to the third quarter of 2005 and remained flat during the first nine months of 2006 as compared to the first nine months of 2005. The quarter-over-quarter decrease reflects the disposition of substantially all of our offshore assets during the first half of 2006, offset in part by an increase of $4.6 million in lease operating expenses attributable to our onshore properties. Despite the sale of our offshore assets, total lease operating expenses remained flat for the first nine months of 2006 as compared to the corresponding nine months of 2005. The increase in onshore lease operating expenses both quarter-over-quarter and period-over-period is due to a combination of factors, including (i) the continued expansion of our onshore operating base through the acquisition of approximately 300 producing wells in South Texas during the fourth quarter of 2005 and the addition of 339 newly developed wells since the end of the third quarter of 2005; (ii) higher costs to operate and maintain our existing property base; and (iii) continued upward pressure on service costs, labor, materials, insurance and property taxes during the first half of 2006 resulting from the continued strong commodity price environment which drives increased activity levels across the industry; offset in part by the stabilization of costs for services, labor and materials during the third quarter of 2006 as a result of lower commodity prices during the quarter.

Severance Tax. Severance tax is a function of production volumes and revenues generated from onshore production. During the third quarter of 2006, severance tax expense increased by 11% on an absolute dollar basis and by $0.10 per Mcfe on a unit of production basis from the third quarter 2005. During the first nine months of 2006, severance tax expense increased by 34% on an absolute dollar basis and by $0.10 on a unit of production basis from the first nine months of 2005. These increases in severance tax expense on an absolute dollar basis are primarily the result of an increase in severance tax rates and an increase in onshore production volumes both quarter-over-quarter and period-over-period.

Depreciation, Depletion and Amortization. The decrease in our depreciation, depletion and amortization expense for both the three-month and nine-month periods ended September 30, 2006 as compared to the corresponding periods of 2005 was primarily a result of lower production volumes subsequent to the sale of our offshore producing assets, offset in part by higher depletion rates during 2006. Our depreciation, depletion and amortization rate for the third quarter of 2006 was 9% higher than the corresponding rate in the third quarter of 2005 due in part to the impact on reserve quantities of lower average wellhead prices for natural gas at September 30, 2006. For the first nine months of 2006, our depreciation, depletion and amortization rate was 16% higher than the corresponding rate during the first nine months of 2005 due primarily to higher finding and development costs.

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General and Administrative Expenses, Net of Overhead Reimbursements and Capitalized General and Administrative Expenses.

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2006	2005	Change	%	2006	2005	Change	%
	(in thousands, except percentages)							
Absolute Dollars								
Gross general and administrative expense	$ 14,588	$ 14,917	$ (329)	-2%	$ 43,994	$ 41,395	$ 2,599	6%
Operating overhead reimbursements	(535)	(508)	(27)	5%	(1,716)	(1,583)	(133)	8%
Capitalized amounts (1)	(4,661)	(4,180)	(481)	12%	(15,575)	(12,260)	(3,315)	27%
General and administrative expense, net	$ 9,392	$ 10,229	$ (837)	-8%	$ 26,703	$ 27,552	$ (849)	-3%

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2006	2005	Change	%	2006	2005	Change	%
	($ per Mcfe, except percentages)							
Unit of Production Mcfe								
Gross general and administrative expense	$ 0.78	$ 0.53	$ 0.25	47%	$ 0.64	$ 0.47	$ 0.17	36%
Operating overhead reimbursements	(0.03)	(0.02)	(0.01)	50%	(0.02)	(0.02)		
Capitalized amounts (1)	(0.25)	(0.15)	(0.10)	67%	(0.23)	(0.14)	(0.09)	64%
General and administrative expense, net	$ 0.50	$ 0.36	$ 0.14	39%	$ 0.39	$ 0.31	$ 0.08	26%

(1) Includes only those internal general and administrative costs that are directly associated with our acquisition, exploration and development activities, such as salaries, benefits and incentive compensation for geological and geophysical

employees and other specifically identifiable non-payroll costs. These capitalized general and administrative costs do not include costs related to production operations, general corporate overhead or other activities that are not directly attributable to our acquisition, exploration and development efforts.

For the three months ended September 30, 2006, both gross and net general and administrative expenses were lower than the corresponding three-month period of 2005. Although we incurred higher salaries, benefits, incentive and stock compensation expenses, legal, consulting and financial advisory fees and office rent and utilities during the third quarter of 2006, these increases were less than the additional outside legal and professional advisory fees of $3.8 million incurred during the third quarter of 2005 in connection with the review of an acquisition which was not consummated. Excluding these additional 2005 advisory expenses, gross and net general and administrative expenses for the third quarter of 2006 would have been higher on a quarter over quarter basis by $3.5 million, or 31%, and $3.0 million, or 46%, respectively.

For the three months ended September 30, 2006, capitalized general and administrative expenses were $0.5 million, or 12%, higher than capitalized costs during the third quarter of 2005. This increase corresponds directly to an increase in salaries, benefits and incentive and stock compensation for our geological and geophysical employees who are directly associated with our acquisition, exploration and development activities.

For the first nine months of 2006, gross general and administrative expenses were higher than the first nine months of 2005 by $2.6 million, or 6%, and net general and administrative expenses were lower for the corresponding nine-month period by $0.8 million, or 3%. This increase in gross general and administrative expenses during the first nine months of 2006 was due to a combination of factors, including (i) higher salaries, benefits, incentive and stock compensation, legal, consulting and financial advisory fees and office rent and utilities; and (ii) additional expenses of approximately $2.3 million, consisting of $1.4 million in bonuses paid to certain employees in connection with the completion of the sale of our Gulf of Mexico assets and approximately $0.9 million in severance payments to certain employees in our offshore group who were terminated following the sale of the assets. These increases during the first nine months of 2006 were partially offset by certain additional expenses incurred during the first nine months of 2005 including (i) $5.0 million in connection with the February 2005 renegotiation of executive employment agreements; and (ii) $3.8 million in additional outside legal and professional advisory fees expensed during the third quarter of 2005 in connection with the review of an acquisition which was not consummated. Excluding the additional $2.3 million in additional expenses during the first nine months of 2006 (of which $1.2 million was capitalized) and the additional $8.8 million in expenses during the first nine months for 2005, gross general and administrative expenses would reflect an increase of $9.1 million, or 28%, and net general and administrative expenses would reflect an increase of $6.8 million, or 36%, for the first nine months of 2006 as compared to the corresponding period of 2005.

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For the nine months ended September 30, 2006, capitalized general and administrative expenses were $3.3 million, or 27% higher than capitalized costs during the corresponding nine months of 2005. This increase, which more than offsets the above noted increase in gross general and administrative expenses, corresponds directly to an increase in salaries, benefits and incentive and stock compensation for our geological and geophysical employees who are directly associated with our acquisition, exploration and development activities and includes $1.2 million in additional compensation for bonuses paid in connection with the sale of our offshore assets during the first nine months of 2006. On a per-unit of production basis, gross, net and capitalized general and administrative expenses were higher during the three-month and nine-month periods of 2006 and reflect the increase in gross general and administrative expense during 2006, primarily as a result of higher salaries, benefits, incentive and stock compensation, legal, consulting and financial advisory fees and office rent and utilities and the decrease in production volume resulting primarily from the sale of our offshore assets.

Other Income and Expense, Interest and Taxes

Other Income and Expense. For the third quarter of 2006, other income and expense totaled $8.3 million and was comprised of income of (i) $5.7 million of interest income earned on cash designated for potential reinvestment in like-kind exchange transactions under Section 1031 of the Internal Revenue Code (see Note 1 Summary of Organization and Significant Accounting Policies *Designated Cash*), of which $4.1 million was earned during the third quarter of 2006 and $1.6 million was earned during the first and second quarters of 2006 and reclassified during the third quarter of 2006 from the line item other revenue , and (ii) $2.6 million of refunds of prior years severance tax expense. For the third quarter of 2005, other income and expense was comprised of $0.1 million of refunds of prior years severance tax expense. Refunds of prior years severance tax expense relate to our July 2002 application and receipt from the Railroad Commission of Texas of a high-cost/tight-gas formation designation for a portion of our South Texas production. For qualifying wells, production is either exempt from tax or taxed at a reduced rate until certain capital costs are recovered.

For the first nine months of 2006, other income and expense totaled $10.5 million and was comprised of (i) $5.7 million of interest income earned on designated cash and (ii) $4.8 million related to refunds of prior years severance tax expense. For the first nine months of 2005, other income and expense included (i) income of $2.5 million related to refunds of prior years severance tax expense and (ii) expense of $2.8 million related to a payout settlement at East Cameron 82/83 during the first quarter of 2005, whereby our working interest in the A3 well was subsequently reduced from 50% to 35%.

Interest Expense, Net of Amounts Capitalized

Interest and Average Borrowings	Three Months Ended September 30, 2006	2005	Change		Nine Months Ended September 30, 2006	2005	Change	
	(dollars in thousands)							
Interest Expense, net:								
Gross interest [(1)]	$ 6,173	$ 5,898	$ 275	5%	$ 24,000	$ 16,943	$ 7,057	42%
Capitalized interest	(993)	(2,357)	1,364	-58%	(3,648)	(6,772)	3,124	-46%
Interest expense, net	$ 5,180	$ 3,541	$ 1,639	46%	$ 20,352	$ 10,171	$ 10,181	100%
Average Borrowings:								
Bank credit facility	$ 147,000	$ 175,000	$ (28,000)	-16%	$ 261,000	$ 172,000	$ 89,000	52%
Senior subordinated notes	175,000	175,000			175,000	175,000		
Total borrowings	$ 322,000	$ 350,000	$ (28,000)	-8%	$ 436,000	$ 347,000	$ 89,000	26%
Average Interest Rate:								

Bank credit facility [2]	7.40%	5.64%	1.76%	31%	6.67%	5.14%	1.53%	30%
Senior subordinated notes	7.00%	7.00%			7.00%	7.00%		

(1) Includes commitment fees, letter of credit fees, amortization of deferred financing costs and other non-loan related charges of $0.3 million for each of the three months ended September 2006 and 2005, respectively, and $1.6 million and $0.9 million for the nine months ended September 2006 and 2005, respectively.

(2) Includes letter of credit and commitment fees.

For the three months ended September 30, 2006, gross interest expense increased 5% due to an increase of 176 basis points in the average interest rate for our bank debt, offset in part by a $28 million decrease in our average outstanding bank borrowings quarter-over-quarter. For the nine months ended September 30, 2006, gross interest expense was 42% higher than the corresponding nine-month period of 2005 due to an $89 million increase in our average outstanding bank borrowings, combined with a 153 basis point increase in the average interest rate for our bank debt. In addition, gross interest expense for the nine-month period ended September 30, 2006 includes an additional $0.6 million for debt extinguishment incurred in connection with the decrease in the borrowing base of our revolving credit facility upon completion of the Gulf of Mexico asset sale transactions.

Our average bank debt increased after the first quarter of 2005 and through the end of the first quarter of 2006, as we utilized bank borrowings to fund acquisitions in East Texas and South Texas and to settle obligations under derivative contracts. At the end of the first quarter and during the second quarter of 2006, we used a portion of the proceeds from the sale of our Gulf of Mexico assets to repay and reduce bank borrowings by a net $322 million to an outstanding balance of $100 million at June 30, 2006. During the third quarter of 2006, we increased bank borrowings by a net $87 million, to $187 million, in order to fund our exploration and development activities. Although the majority of our bank debt bears interest at LIBOR-based rates, the Federal Reserve raised rates by one quarter of a percent eight times during 2005 and four times during the first nine months of 2006. We expect to continue to see an increase in the average interest rates on our bank debt if the Federal Reserve continues to increase interest rates.

Capitalized interest declined by 58% during the third quarter of 2006 and by 46% during the first nine months of 2006, as compared to the corresponding three-month and nine-month periods of 2005. These declines correspond directly to the $75.8 million decrease in the balance of our unevaluated properties related to our Gulf of Mexico assets that were sold during the first half of 2006. We expect our unevaluated property balance to remain lower than historical levels given the lower cost structure of onshore projects and the shorter timeline to complete the evaluation of onshore projects. Accordingly, we also expect our capitalized interest to be lower and, in turn, our net interest expense to be higher as a result of the shift in our operating focus onshore.

Income Tax Provision. Our provision for taxes includes both state and federal taxes. In May 2006, the State of Texas enacted substantial changes to its tax structure beginning in 2007 by implementing a new margin tax of 1% to be imposed on revenues less certain costs, as specified in the legislation. During the nine months ended September 30, 2006, we increased our provision for income taxes by an additional $6.8 million to provide for deferred taxes to the State of Texas under the newly enacted state margin tax.

Liquidity and Capital Resources

Our principal requirements for capital are to fund our acquisition, exploration, and development activities and to satisfy our contractual obligations, including the repayment of debt and any amounts owing during the period relating to our derivative contracts, as well as repurchases of common stock from time to time. Our principal uses of capital related to our acquisition, exploration and development activities include the following:

§ Drilling and completing new natural gas and oil wells;

§ Constructing and installing new production infrastructure;

§ Acquiring additional reserves and producing properties;

§ Acquiring and maintaining our lease acreage position and our seismic resources;

§ Maintaining, repairing, and enhancing existing natural gas and oil wells;

§ Plugging and abandoning depleted or uneconomic natural gas and oil wells; and

§ General and administrative costs directly associated with our acquisition, exploration and development activities, including payroll and other expenses attributable to only our geological and geophysical employees.

During the nine months ended September 30, 2006, we spent approximately $458.6 million on these and other capital activities and in October 2006, our Board of Directors increased our capital expenditure budget for 2006 to $584 million from $521 million. To maintain the flexibility of our capital program, we typically do not enter into material long-term obligations with any of our drilling contractors or service providers with respect to our operated properties; however, we may choose to do so if we believe an opportunity is economically beneficial, as is the case with certain of our contracts for drilling rigs. See Note 4 Commitments and Contingencies *Drilling Contracts*. We will continue to evaluate our capital spending throughout the fourth quarter of 2006. Actual spending levels frequently vary due to a variety of factors, including drilling results, natural gas prices, economic conditions, any future acquisitions and the outcome of our Board s review of strategic alternatives.

We believe that operating cash flow, designated cash balances and our credit facility will be adequate to meet our capital and operating requirements during the fourth quarter of 2006. We continuously monitor our working capital and debt position, as well as coordinate our capital expenditure program with expected cash flows and projected debt repayment schedules. In addition to utilizing operating cash flow, designated cash balances and borrowings under our revolving credit facility, we believe we could finance capital expenditures with issuances of additional debt or equity securities and/or via development arrangements with industry partners.

Sources of Liquidity and Capital Resources

Our primary sources of cash during the first nine months of 2006 were from funds generated from operations, bank borrowings and proceeds from the sale of substantially all of our Gulf of Mexico assets. We intend to fund our future capital expenditure programs, including any future acquisitions, as well as our contractual commitments, including any required settlement of derivative contracts, with our cash flows from operations, designate cash balances, borrowings under our revolving credit facility and potential issuances of additional debt and/or equity securities.

Available Liquidity and Designated Cash. The following table summarizes our total available liquidity and designated cash at September 30, 2006 and December 31, 2005:

	September 30, 2006	December 31, 2005
	(in thousands)	
Available Liquidity:		
Revolving credit facility borrowing base	$ 500,000	$ 600,000
Outstanding borrowings	(187,000)	(422,000)
Letters of credit	(300)	(300)
Unused borrowing capacity	312,700	177,700
Cash and cash equivalents	18,435	7,979
Total available liquidity	$ 331,135	$ 185,679
Available Liquidity and Designated Cash:		
Total available liquidity	$ 331,135	$ 185,679
Designated cash	314,043	
Total available liquidity and designated cash	$ 645,178	$ 185,679

At September 30, 2006, we had $312.7 million of available borrowing capacity under our revolving credit facility. This facility provides a lending commitment of $750 million with an additional $100 million available upon request and with prior approval from our lenders. Amounts available for borrowing under the credit facility are limited to a borrowing base, which as of October 1, 2006 remained at $500 million. Cash and cash equivalents totaled $18.4 million and included approximately $7.6 million in funds released from designated cash in late September 2006 (see Note 1 Summary of Organization and Significant Accounting Policies *Designated Cash*). In addition, we had designated cash of $314.0 million, representing remaining proceeds from the sale of substantially all of our Gulf of Mexico assets, which remains deposited with qualified intermediaries for potential reinvestment in like-kind exchange transactions under Section 1031 of the Internal Revenue Code on or before November 27, 2006. We expect that the remaining escrowed proceeds of $314.0 million will be released from escrow and reclassified as cash during the fourth quarter of 2006. In connection with the release of the $314.0 million in designated cash, during the fourth quarter of 2006, we expect to recognize a taxable gain of approximately $250 million to $260 million on the sale of these assets and estimate that the net income tax liability associated with this gain, after considering our available net operating losses, alternative minimum tax credits and other corporate tax attributes, will be approximately $35 million to $40 million.

Cash Provided by Operating Activities. Net cash provided by operating activities decreased from $384.0 million during the first nine months of 2005 to $339.2 million during the first nine months of 2006. This 12% decrease was primarily due to commodity prices, production volumes, operating expenses and fluctuations in working capital caused by timing of cash receipts and disbursements. During the first nine months of 2006, we realized slightly higher commodity prices but experienced significantly lower production volumes than in the same period of 2005 due primarily to the sale of our Gulf of Mexico assets, combined with continued hurricane-related curtailments from offshore Louisiana fields prior to their sale. The reduction in operating cash flow caused by these factors was offset in part by lower operating expenses resulting from the disposition of substantially all of our offshore assets as compared to the same nine-month period of 2005.

At September 30, 2006, we had a working capital balance of $39.6 million. This balance fluctuates as a result of the timing and amount of cash receipts and disbursements for operating activities, including payments required under our existing derivative contracts, and borrowings or repayments under our revolving credit facility. As a result, we often have a working capital deficit or a relatively small amount of positive working capital, which we believe is typical of companies of our size in the exploration and production industry.

Access to Capital Markets. If a significant acquisition or other strategic opportunity arises, we may choose to access the public capital markets to issue additional debt and/or equity securities. We have the capacity to offer up to $750 million of our common stock, preferred stock, depositary shares and debt securities, or a combination of any of these securities, under effective shelf registration statements filed with the SEC in March and October 2004.

Uses of Liquidity and Capital Resources

During the first nine months of 2006, our primary uses of cash were to fund exploration and development expenditures, repurchase common stock, repay bank borrowings and fund required payments under derivative instruments and other contractual obligations. In addition, during the first nine months of 2006, we made aggregate cash payments of $19.4 million for interest and no cash payments for taxes. Subject to the outcome of our Board s ongoing review of strategic alternatives described above (see Strategic Restructuring Plan above), we may use the remaining proceeds from the sale of our Gulf of Mexico assets for developing our existing onshore assets, acquiring additional onshore assets, and/or repaying indebtedness.

Capital Expenditures. Total capital expenditures during the first nine months of 2006 were $458.6 million, which includes $11.4 million of accrued and unpaid exploration and development costs. This represented an increase of $38.1 million, or 9%, over the first nine months of 2005. Approximately $21 million of this increase relates to the payment of a net profits interest accelerated by the sale of certain offshore assets. During the first nine months of 2006, we invested a net $456.6 million in natural gas and oil properties and we spent $2.0 million for non-oil and gas property and equipment. Non-oil and gas property and equipment includes expenditures for the expansion and renovation of our Houston office lease space, and upgrades to our information technology systems and office equipment and compares to $0.8 million spent during the first nine months of 2005. During the first nine months of 2006, we spent 81% of our total natural gas and oil expenditures of $456.6 million onshore and 15% offshore with the balance of 4% on capitalized interest and general and administrative costs. We completed the drilling of 268 gross wells (202.9 net), of which 91%, or 244 (185.2 net), were successful and 24 (17.7 net) were unsuccessful, with an additional 31 wells (18.9 net) in progress at September 30, 2006, including one offshore exploratory well that we are participating in at West Cameron 132. All wells drilled during the first nine months of 2006 were drilled onshore, with the exception of one offshore dry hole that we participated in at Eugene Island 357 and a second offshore well that we elected to participate in at West Cameron 39 that was successful.

For the first nine months of 2006, investing activities includes net proceeds from the sale of assets totaling a net $721.6 million, of which we used $374 million to repay borrowings under our revolving credit facility during the first half of 2006 and initially deposited $323.7 with qualified intermediaries for potential reinvestment in like-kind exchange transactions under Section 1031 of the Internal Revenue Code, with the balance of the proceeds from the sale used for working capital purposes. During the third quarter of 2006, we released $9.6 million of cash designated for like-kind exchanges, of which $2.0 million was used for qualified reinvestments in natural gas and oil properties and $7.6 million was reclassified as cash due to the expiration of the 180-day reinvestment period under Section 1031 of the Internal Revenue Code. The 180-day reinvestment period for the balance of the designated cash expires November 27, 2006, at which time we expect that the remaining escrowed proceeds will be released and reclassified as cash.

	Natural Gas and Oil Expenditures and Dispositions			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(in thousands)			
Producing property acquisitions [(1)]	$ (8,436)	$ 57	$ 38,809	$ 31,691
Leasehold and lease acquisition costs [(2)]	10,090	9,680	38,055	45,255
Development	111,811	102,732	304,468	250,784
Exploration	29,200	28,857	75,220	91,986
Total natural gas and oil capital expenditures	142,665	141,326	456,552	419,716

Producing property dispositions [3]	2,043		(721,606)	(150)
Net natural gas and oil capital expenditures	$ 144,708	$ 141,326	$ (265,054)	$ 419,566

(1) For the three months ended September 30, 2006, includes an adjustment of approximately $9.0 million to a $30 million accrual made during the second quarter of 2006 for an estimated net profits interest payment of $21 million paid in August 2006 to the predecessor owner of certain offshore properties acquired by us in October 2003 which payment was accelerated by the sale of certain offshore Louisiana assets completed June 1, 2006.

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For the nine months ended September 30, 2006, includes the following: (i) the above mentioned $21.0 million payment for a net profits interest paid in August 2006 to the predecessor owner of certain offshore properties acquired by us in October 2003; (ii) $21.3 million paid for producing properties in East Texas in April 2006; and (iii) a final purchase price adjustment and return of capital of $4.1 million received during the first quarter of 2006, representing a reduction to the $159.0 net purchase price paid for the South Texas properties acquired on November 30, 2005 from Kerr-McGee Oil & Gas Onshore LP and Westport Oil and Gas

Company, L.P.

(2) For the three months ended September 30, 2006 and 2005, includes capitalized interest and general and administrative expenses of $5.7 million and $6.6 million, respectively. For the nine months ended September 30, 2006 and 2005, includes capitalized interest and general and administrative expenses of $19.2 million and $19.1 million, respectively.

(3) For the three months ended September 30, 2006, a net purchase price adjustment and additional proceeds of $0.6 million from the sale of the Texas portion of our offshore assets and a purchase price adjustment and additional payment by us of $2.6 million in connection with the sale of our offshore

Louisiana assets.

For the nine months ended September 30, 2006 includes: (i) net proceeds from the sale of our Louisiana Gulf of Mexico assets of $530.8 million, net of $4.4 million in fees associated with completion of the transaction and $2.6 million in purchase price adjustments; (ii) net proceeds from the sale of the Texas portion of our Gulf of Mexico assets of $190.8 million, net of $1.5 million in transaction fees and additional proceeds resulting from the final purchase price adjustment of $0.6 million; and (iii) $7.9 million in net proceeds for the sale of other assets.

Stock Repurchases. On November 4, 2005, our Board of Directors approved discretionary repurchases from time to time over twelve months of up to $200 million in company stock in conjunction with the divesture of all of our Gulf of Mexico assets. For the nine months ended September 30, 2006, we repurchased 1,176,500 shares, or approximately 4% of our outstanding common stock, in the open market for a total cost of approximately $61.6 million. All repurchases were paid for in cash and funded with cash on hand or borrowings under our revolving credit facility. All repurchased shares were retired. No repurchases were made during the third quarter of 2006.

Debt Repayments. During the first nine months of 2006, total long-term debt decreased by a net $235 million as we used a portion of the proceeds received from the sale of our Gulf of Mexico assets to repay bank borrowings.

Future Commitments. The following table provides estimates of the timing of future payments that we were obligated to make based on agreements in place at September 30, 2006. All amounts listed in the following table are categorized as liabilities on our balance sheet with the exception of outstanding letters of credit issued for performance obligations, lease payments for operating leases and obligations under long-term drilling, seismic and financial advisory services agreements. At September 30, 2006, we did not have any capital leases. The table includes references to our financial statements for information regarding the listed obligation. Contractual obligations relating to our revolving credit facility and our senior notes include only payments of principal.

			Future Commitments Payments Due by Period			
	Reference	**Total**	**1 year or less**	**2 3 years**	**4 5 years**	**after 5 years**
			(in thousands)			
Contractual Obligations:						
Revolving credit facility, due November 2010	Note 2	$ 187,000	$	$	$ 187,000	$
7% senior subordinated notes, due June 2013	Note 2	175,000				175,000
Derivative instruments	Note 1	27,575	5,251	22,324		
Operating leases	Note 4	5,382	1,857	3,516	9	
Letters of credit	Note 4	300	300			
Drilling contracts	Note 4	11,640	9,644	1,996		
Seismic contracts	Note 4	3,014	3,014			
		409,911	20,066	27,836	187,009	175,000
Other Long-Term Obligations:						
Asset retirement obligations	Note 1	40,015		92		39,923
Supplemental Executive Retirement Plan	Note 4	2,229	100	265	261	1,603
		42,244	100	357	261	41,526
Total Contractual Obligations and Commitments:		$ 452,155	$ 20,166	$ 28,193	$ 187,270	$ 216,526

In addition to the contractual obligations listed on the above table, our balance sheet at September 30, 2006 reflects accrued interest payable on our revolving credit facility of approximately $0.2 million, which is payable over the next 90-day

period. We expect to make annual interest payments of $12.3 million per year on our $175 million of 7% senior subordinated notes due June 2013. During the fourth quarter of 2006 and in connection with expected release of the remaining $314.0 million in designated cash, due to the expiration of the 180-day reinvestment period under Section 1031 of the Internal Revenue Code, we expect to recognize a taxable gain of approximately $250 million to $260 million on the sale of these assets and estimate that the net income tax liability associated with this gain, after considering our available net operating losses, alternative minimum tax credits and other corporate tax attributes, will be approximately $35 million to $40 million.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Market Risk

Our major market risk exposure continues to be the prices applicable to our natural gas and oil production. The sales price of our production is primarily driven by the prevailing market price. Historically, prices received for our natural gas and oil production have been volatile and unpredictable.

Interest Rate Risk

At September 30, 2006, our total debt was $362 million, of which approximately 48%, or $175 million, bears interest at a fixed interest rate of 7% per year. The remaining 52% of our total debt balance at September 30, 2006, or $187 million, represents our bank debt, which bears interest at floating or market interest rates that at our option are tied to prime rate or LIBOR at our option. Fluctuations in market interest rates will cause our annual interest costs to fluctuate. During the first nine months of 2006, the interest rate on our outstanding bank debt averaged 6.67% per year. If the balance of our bank debt at September 30, 2006 were to remain constant, a 10% change in market interest rates would impact our cash flow by approximately $0.2 million per quarter.

Commodity Price Risk

We utilize derivative commodity instruments to hedge future sales prices on a portion of our natural gas and oil production to achieve more predictable cash flows, as well as to reduce our exposure to adverse price fluctuations of natural gas. Our derivatives are not held for trading purposes. While the use of certain hedging arrangements limits the downside risk of adverse price movements, it also limits increases in future revenues in the event of favorable price movements. In addition, because all of our open derivative contracts ceased to qualify for hedge accounting during the first quarter of 2006, our future earnings are expected to become more volatile as all subsequent changes in the fair market value of open contracts will be recognized as an increase or reduction to natural gas and oil revenues (see Note 1 Summary of Organization and Significant Accounting Policies *Derivative Instruments and Hedging Activities)*. We continue to evaluate opportunities to hedge both our production and basis differential exposure and may elect to do so if market conditions warrant. In addition, if we believe market conditions are favorable, we may elect to liquidate additional derivative contract positions in the future.

The use of hedging transactions also involves the risk that the counterparties are unable to meet the financial terms of such transactions. Hedging instruments that we typically use include swaps, collars and options, which we generally place with investment grade financial institutions that we believe present minimal credit risks. We believe that our credit risk related to our natural gas hedging instruments is no greater than the risk associated with the underlying primary contracts and that the elimination of price risk reduces volatility in our reported results of operations, financial position and cash flows from period to period and lowers our overall business risk. However, as a result of our hedging activities, we may be exposed to greater credit risk in the future.

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Changes in Fair Value of Derivative Instruments

The following table summarizes the change in the fair value of our derivative instruments for each of the nine-month periods from January 1 to September 30, 2006 and 2005, and provides the fair value at the end of each period.

	Nine Months Ended September 30,	
	2006	**2005**
Change in Fair Value of Derivative Instruments:	Before Tax (in thousands)	
Fair value of contracts at January 1	$ (417,658)	$ (75,149)
Realized loss on contracts settled during period [1]	67,664	100,726
(Decrease) increase in fair value of all open contracts	322,419	(722,256)
Net change during period	390,083	(621,530)
Fair value of contracts outstanding at September 30	$ (27,575)	$ (696,679)

(1) Includes $15.2 million paid during the first nine months of 2006 to liquidate and settle contracts. In June 2006, we paid $14.3 million to liquidate and settle contracts covering 60,000 MMBtu per day for each of the months July through December 2006. This liquidation and settlement was made in connection with the completion of the sale of our Gulf of Mexico assets on June 1, 2006 and was required under the terms of our revolving credit facility. In

August 2006, we elected to liquidate and settle open derivative contracts representing 20,000 MMBtu per day of hedged production for each of the months September and October 2006. The cost to liquidate and settle these contracts was approximately $0.9 million.

Summary of Derivative Contracts

As of November 8, 2006, the following table summarizes, on a daily basis, our natural gas hedges for the fourth quarter of 2006 and for 2007 and 2008.

Year	Period (Months)	Transaction Type	Daily Volume (MMBtu/day)	NYMEX Price ($/MMBtu)	Floor Price ($/MMBtu)	Ceiling Price ($/MMBtu)
2006	Oct Dec	Swap	20,000	$ 5.87		
2006	Oct Dec	Swap	10,000	5.94		
2006	Oct Dec	Costless collar	10,000		$ 5.50	$ 7.20
2006	Oct Dec	Costless collar	20,000		5.50	7.26
2006	Oct Dec	Costless collar	20,000		5.75	7.20
2006	Oct Dec	Costless collar	50,000		5.82	7.00
2006	Oct	Costless collar	10,000		6.00	7.00
2006	Nov Dec	Costless collar	30,000		6.00	7.00
2006	Oct Dec	Costless collar	20,000		6.00	7.02
2006	Oct Dec	Costless collar	10,000		6.00	7.05

2007	Jan Dec	Costless collar	20,000	$ 5.00	$ 6.50
2007	Jan Dec	Costless collar	10,000	5.00	6.79
2008	Jan Dec	Costless collar	20,000	$ 5.00	$ 5.72

For natural gas, transactions are settled based upon the NYMEX price on the final trading day of the month. In order to determine fair market value of our derivative instruments, we obtain market-based quotes from external counterparties.

With respect to any particular swap transaction, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price for the transaction, and we are required to make payment to the counterparty if the settlement price for any settlement period is greater than the swap price for the transaction. For any particular collar transaction, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price for the transaction, and we are required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling price for the transaction. We are not required to make or receive any payment in connection with a collar transaction if the settlement price is between the floor and the ceiling prices.

Item 4. Controls and Procedures

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we conducted an evaluation of our disclosure controls and procedures, as this term is defined under Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the Exchange Act). Based on this evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures were effective as of the end of the period covered by this Quarterly Report.

Changes in Internal Control Over Financial Reporting

No change in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) occurred during the three months ended September 30, 2006, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

See Note 4 Commitments and Contingencies *Legal Proceedings* to the accompanying notes to consolidated financial statements for discussion of the material legal proceedings to which we are a party.

Item 1A. Risk Factors

As of November 8, 2006, there have been no material changes for the risk factors previously disclosed in Item 1A. Risk Factors of our Annual Report on Form 10-K for the year ended December 31, 2005, as amended, and in Item 1A. of Part II of our Quarterly Report on Form 10-Q for the quarters ended March 31, 2006 and June 30, 2006, except as follows.

Our hedging activities have resulted in financial losses and reduced our income and may continue to do so in the future.

By the end of the first quarter of 2006, all of our open derivative contracts ceased to qualify for hedge accounting. As a result, our future earnings are expected to become more volatile, as mark-to-market accounting will be utilized, and all subsequent changes in the fair market value of open contracts will be recognized as an increase or reduction to natural gas and oil revenues. At September 30, 2006, an unrealized loss of $44.5 million, net of tax, remains deferred in accumulated other comprehensive income. This loss represents the fixed value of our remaining open derivative contracts deferred in accumulated other comprehensive income at the time they ceased to qualify for hedge accounting. All remaining deferred losses will be reclassified and recognized in future earnings at the time when sale of the related forecasted natural gas production occurs. Over the next 12-month period, we expect to reclassify from accumulated other comprehensive income to earnings a loss of $34.3 million, net of tax, with $10.2 million to be recognized thereafter.

We could lose certain leasehold rights if we do not drill all the wells that are necessary to hold our acreage, especially in the Rocky Mountains, before the initial lease terms expire.

After the sale of substantially of our Gulf of Mexico properties, our future growth plans rely in part on establishing significant production and reserves in the Rocky Mountains, which as of December 31, 2005 represented approximately 4% of our onshore proved reserves. At September 30, 2006, approximately 80% of our total onshore undeveloped acreage is located in the Rockies and will expire within the next three-year period. We also have undeveloped acreage offshore Louisiana. We may have difficulty drilling all of the wells that are necessary to hold this acreage before the initial lease terms expire, which could result in the loss of certain leasehold rights.

Item 5. Other Information

As previously reported in a Form 8-K filed on October 27, 2006, our Board of Directors, based on the recommendation of the Compensation Committee, approved certain amendments to the employment agreements with each of our executive

officers to comply with Section 409A of the Internal Revenue Code. See Item 6. Exhibits for copies of these amendments previously filed.

Item 6. Exhibits

EXHIBITS	DESCRIPTION
10.1[(1)(2)]	Amendment No. 1, dated October 24, 2006, to the Amended and Restated Employment Agreement dated February 8, 2005 between The Houston Exploration Company and William G. Hargett (filed as Exhibit 10.1 to Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.2[(1)(2)]	Amendment No. 1, dated October 24, 2006, to the Amended and Restated Employment Agreement dated February 8, 2005 between The Houston Exploration Company and Steven L. Mueller (filed as Exhibit 10.2 to Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.3[(1)(2)]	Amendment No. 1, dated October 24, 2006, to the Employment Agreement dated January 8, 2006 between The Houston Exploration Company and Robert T. Ray (filed as Exhibit 10.3 to Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.4[(1)(2)]	Amendment No. 1, dated October 24, 2006, to the Employment Agreement dated March 27, 2006, between The Houston Exploration Company and Carolyn M. Campbell (filed as Exhibit 10.4 to Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.5[(1)(2)]	Amendment No. 1, dated October 24, 2006, to the Amended and Restated Employment Agreement dated February 8, 2005 between The Houston Exploration Company and Roger B. Rice (filed as Exhibit 10.5 to Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.6[(1)(2)]	Amendment No. 1, dated October 24, 2006, to the Employment Agreement dated April 13, 2005, between The Houston Exploration Company and Jeffrey B. Sherrick (filed as Exhibit 10.6 to Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.7[(1)(2)]	Amendment No. 1, dated October 24, 2006, to the Amended and Restated Employment Agreement dated February 8, 2005 between The Houston Exploration Company and James F. Westmoreland (filed as Exhibit 10.7 to Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.8[(1)(2)]	Amendment No. 1, dated October 24, 2006, to the Employment Agreement dated February 10, 2005, between The Houston Exploration Company and Joanne C. Hresko (filed as Exhibit 10.8 to Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.9[(1)(2)]	Amendment No. 1, dated October 24, 2006, to the Employment Agreement dated March 10, 2005, between The Houston Exploration Company and John E. Bergeron, Jr. (filed as Exhibit 10.9 to Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference)
12.1	Computation of ratio of earnings to fixed charges.

31.1	Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Robert T. Ray, Chief Financial Officer, as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Robert T. Ray, Chief Financial Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(1) Previously filed.

(2) Identified as a management contract or compensation plan or arrangement

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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 HOUSTON EXPLORATION COMPANY

Date: November 8, 2006	By: /s/ William G. Hargett William G. Hargett Chairman, President and Chief Executive Officer
Date: November 8, 2006	By: /s/ Robert T. Ray Robert T. Ray Senior Vice President and Chief Financial Officer
Date: November 8, 2006	By: /s/ James F. Westmoreland James F. Westmoreland Vice President and Chief Accounting Officer

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Index to Exhibits

EXHIBITS	DESCRIPTION
10.1[(1)(2)]	Amendment No. 1, dated October 24, 2006, to the Amended and Restated Employment Agreement dated February 8, 2005 between The Houston Exploration Company and William G. Hargett (filed as Exhibit 10.1 to Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.2[(1)(2)]	Amendment No. 1, dated October 24, 2006, to the Amended and Restated Employment Agreement dated February 8, 2005 between The Houston Exploration Company and Steven L. Mueller (filed as Exhibit 10.2 to Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.3[(1)(2)]	Amendment No. 1, dated October 24, 2006, to the Employment Agreement dated January 8, 2006 between The Houston Exploration Company and Robert T. Ray (filed as Exhibit 10.3 to Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.4[(1)(2)]	Amendment No. 1, dated October 24, 2006, to the Employment Agreement dated March 27, 2006, between The Houston Exploration Company and Carolyn M. Campbell (filed as Exhibit 10.4 to Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.5[(1)(2)]	Amendment No. 1, dated October 24, 2006, to the Amended and Restated Employment Agreement dated February 8, 2005 between The Houston Exploration Company and Roger B. Rice (filed as Exhibit 10.5 to Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.6[(1)(2)]	Amendment No. 1, dated October 24, 2006, to the Employment Agreement dated April 13, 2005, between The Houston Exploration Company and Jeffrey B. Sherrick (filed as Exhibit 10.6 to Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.7[(1)(2)]	Amendment No. 1, dated October 24, 2006, to the Amended and Restated Employment Agreement dated February 8, 2005 between The Houston Exploration Company and James F. Westmoreland (filed as Exhibit 10.7 to Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.8[(1)(2)]	Amendment No. 1, dated October 24, 2006, to the Employment Agreement dated February 10, 2005, between The Houston Exploration Company and Joanne C. Hresko (filed as Exhibit 10.8 to Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.9[(1)(2)]	Amendment No. 1, dated October 24, 2006, to the Employment Agreement dated March 10, 2005, between The Houston Exploration Company and John E. Bergeron, Jr. (filed as Exhibit 10.9 to Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference)
12.1	Computation of ratio of earnings to fixed charges.
31.1	

	Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Robert T. Ray, Chief Financial Officer, as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Robert T. Ray, Chief Financial Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(1) Previously filed.

(2) Identified as a management contract or compensation plan or arrangement