HOUSTON EXPLORATION CO
Form 10-Q
May 09, 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 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 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	**22-2674487**
(State or Other Jurisdiction of Incorporation or Organization)	**(IRS Employer Identification No.)**
1100 Louisiana, Suite 2000 Houston, Texas	**77002-5215**
(Address of Principal Executive Offices)	**(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 filer o

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

As of May 9, 2006, 29,092,280 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 be, will continue, will likely result, and similar expressio Forward-looking statements are based on current expectations and assumptions that are subject to 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 this Quarterly Report on Form 10-Q and in our Annual Report on Form 10-K for the year ended December 31, 2005, as amended. 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 made available free of charge on our website at http://www.houstonexploration.com as soon as reasonably practicable after we electronically file such material with, or otherwise furnish it to, the Securities and Exchange Commission (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. In this Quarterly Report, unless the context requires otherwise, we are reporting historical results as of March 31, 2006 and December 31, 2005, and for the three months ended March 31, 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)

	March 31, 2006	December 31, 2005
Assets:		
Cash and cash equivalents	$ 19,538	$ 7,979
Accounts receivable	115,012	146,020
Inventories	3,407	2,726
Deferred tax asset	38,952	145,922
Prepayments and other	16,500	19,709
Total current assets	193,409	322,356
Natural gas and oil properties, full cost method		
Unevaluated properties	82,337	107,146
Properties subject to amortization	3,483,903	3,556,755
Other property and equipment	13,031	12,971
	3,579,271	3,676,872
Less: Accumulated depreciation, depletion and amortization	1,742,138	1,658,532
	1,837,133	2,018,340
Other non-current assets	19,624	20,928
Total Assets	$ 2,050,166	$ 2,361,624
Liabilities:		
Accounts payable and accrued expenses	$ 132,234	$ 177,159
Derivative financial instruments	103,080	352,457
Asset retirement obligation	6,967	7,265
Total current liabilities	242,281	536,881
Long-term debt and notes	424,000	597,000
Derivative financial instruments	46,370	65,201
Deferred income taxes	339,190	341,302
Asset retirement obligation	85,009	112,406
Other non-current liabilities	13,943	15,696

Total Liabilities	1,150,793	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, $.01 par value, 100,000,000 shares authorized and 29,077,472 and 28,980,128 shares issued and outstanding at March 31, 2006 and December 31, 2005, respectively	291	289
Additional paid-in capital	303,391	297,218
Retained earnings	693,139	663,367
Accumulated other comprehensive (loss)	(97,448)	(267,736)
Total Stockholders Equity	899,373	693,138
Total Liabilities and Stockholders Equity	$ 2,050,166	$ 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 March 31, 2006	Three Months Ended March 31, 2005
Revenues:		
Natural gas and oil revenues	$ 177,019	$ 165,490
Other	585	230
Total revenues	177,604	165,720
Operating expenses:		
Lease operating	21,812	15,368
Severance tax	6,159	2,934
Transportation expense	2,771	2,766
Asset retirement accretion expense	1,327	1,325
Depreciation, depletion and amortization	83,761	70,603
General and administrative, net of amounts capitalized	8,606	11,123
Total operating expenses	124,436	104,119
Income from operations	53,168	61,601
Other (income) expense	(1,407)	1,454
Interest expense, net of amounts capitalized	8,721	3,434
Income before income taxes	45,854	56,713
Provision for taxes	16,082	23,275
Net income	$ 29,772	$ 33,438
Earnings per share:		
Net income per share basic	$ 1.03	$ 1.17
Net income per share diluted	$ 1.02	$ 1.16
Weighted average shares outstanding basic	29,042	28,499
Weighted average shares outstanding diluted	29,310	28,871

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)

	Three Months Ended March 31, 2006	2005
Operating Activities:		
Net income	$ 29,772	$ 33,438
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	83,761	70,603
Deferred income tax expense	11,524	15,571
Asset retirement accretion expense	1,327	1,325
Stock compensation expense	2,517	1,012
Tax benefit from non-qualified stock options		1,724
Unrealized (gain) loss on derivative instruments	(4,586)	1,424
Changes in operating assets and liabilities:		
Accounts receivable	31,008	7,771
Inventories	(681)	(381)
Prepayments and other	5,409	1,383
Other assets	1,304	1,131
Accounts payable and accrued expenses	(37,481)	(2,488)
Other non-current liabilities	(1,753)	846
Net cash provided by operating activities	122,121	133,359
Investing Activities:		
Investment in property and equipment	(128,391)	(131,138)
Deposit paid for property acquisition	(2,200)	
Dispositions and other	189,371	150
Net cash used in investing activities	58,780	(130,988)
Financing Activities:		
Proceeds from long-term borrowings	163,000	85,000
Repayments of long-term borrowings	(336,000)	(100,000)
Proceeds from issuance of common stock from exercise of stock options	3,213	7,812
Tax benefit from non-qualified stock options	445	
Net cash used in financing activities	(169,342)	(7,188)
Increase (decrease) in cash and cash equivalents	11,559	(4,817)
Cash and cash equivalents, beginning of period	7,979	18,577
Cash and cash equivalents, end of period	$ 19,538	$ 13,760

Supplemental Information:				
Non-cash transactions:				
Investments in property and equipment accrued, not paid	$	7,444	$	(15,489)
Cash paid during period for:				
Interest	$	6,952	$	1,987
Federal and state income taxes				

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 concentrating on growing reserves and production through 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 March 31, 2006, we had operations in five producing regions within the United States: South Texas; the Arkoma Basin of Arkansas and Oklahoma; East Texas; the Uinta and DJ Basins in the Rocky Mountains; and the Gulf of Mexico, which is in the process of being sold.

In November 2005, we announced a strategic plan to restructure the company by pursuing the sale of all our Gulf of Mexico assets and focusing our operations primarily onshore. On March 31, 2006, we completed the sale of the Texas portion of our Gulf of Mexico assets and on April 7, 2006, we entered into a definitive purchase and sale agreement to sell substantially all of our Louisiana Gulf of Mexico assets. See Note 6 Acquisitions and Dispositions *Sale of Texas Gulf of Mexico Assets* and Note 7 Subsequent Events *Pending Sale of Louisiana Gulf of Mexico Assets*. We expect to use the proceeds from the sale of our Gulf of Mexico assets primarily to acquire longer-lived natural gas assets onshore in North America, repay existing bank debt and repurchase company stock. Where prudent, we plan to structure our asset reinvestment in a tax efficient manner.

Principles of Consolidation

Our consolidated financial statements for the period ended March 31, 2006 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 March 31, 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 at 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 based on remaining proved natural gas and oil reserves. 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 computing taxes, preparing accruals of operating costs and production revenues, asset retirement obligations, fair value and effectiveness of derivative instruments and fair value of stock options and the related compensation expense. Because there are numerous uncertainties inherent in the estimation process, actual results could differ materially from these estimates.

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

Reclassifications

Certain reclassifications have been made to prior year amounts to conform to the 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 separate 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 incur production gas volume imbalances in the ordinary course of business. Net deliveries in excess of entitled amounts are recorded as liabilities, while 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 in hand.

At March 31, 2006, we had production imbalances representing assets of $3.2 million and liabilities of $4.8 million. At December 31, 2005, we had production imbalances representing assets of $4.9 million and liabilities of $7.2 million. The primary sources of our production imbalances relate to (i) Eugene Island 331, a property that has been shut-in due to pipeline issues since Hurricane Katrina in late-August 2005, and which property is included in the pending sale of our Louisiana Gulf of Mexico assets and (ii) various Arkoma wells due to imbalances assumed upon our initial acquisition of the properties, which due to their long life and comparatively low rate of production, 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 the balance sheet.

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

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. For us, potentially dilutive common shares consist primarily of employee stock options and restricted common stock.

	Three Months Ended March 31, 2006	2005
	(in thousands)	
Numerator:		
Net income	$ 29,772	$ 33,438
Denominator:		
Weighted average shares outstanding	29,042	28,499
Add dilutive securities: Stock options and restricted stock	268	372
Total weighted average shares outstanding and dilutive securities	29,310	28,871
Earnings per share basic:	$ 1.03	$ 1.17
Earnings per share diluted:	$ 1.02	$ 1.16

For the three months ended March 31, 2006 and 2005, the calculation of shares outstanding for diluted net income per share does not include the effect of outstanding stock options to purchase 658,227 and 377,725 shares respectively, because the exercise price of these shares was greater than the average market price for the respective periods, which would have an antidulitive effect on net income per share.

Comprehensive Income (Loss)

Comprehensive income includes net income and certain items recorded directly to stockholders equity and classified as other comprehensive income. The table below summarizes comprehensive income and provides the components of the change in accumulated other comprehensive income for the three-month periods ended March 31, 2006 and 2005.

	Three Months Ended March 31, 2006	2005
	(in thousands)	
Net income	$ 29,772	$ 33,438
Other comprehensive income (loss)		
Derivative contracts settled and reclassified, net of tax	30,055	9,157
Change in unrealized (loss) fair value of open contracts, net of tax	140,233	(136,859)
Change in accumulated other comprehensive income (loss)	170,288	(127,702)
Comprehensive income (loss)	$ 200,060	$ (94,264)

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 incurred in the acquisition, exploration and development of natural gas and oil reserves are capitalized into a full cost pool. Capitalized costs include costs of all unproved properties, internal costs directly related to our natural gas and oil activities and capitalized interest. We amortize these costs using a unit-of-production method. We compute the provision for depreciation, depletion and amortization quarterly by multiplying production for the quarter by a depletion rate. The depletion rate is determined by dividing our total unamortized cost base by 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 asset retirement obligations); less,
- unevaluated properties and their related costs; less,

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

estimates for salvage.

Costs associated with unevaluated properties are excluded from the amortization 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 of natural gas and oil properties are accounted for as adjustments to the full cost pool, with no gain or loss recognized, unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves.

Under full cost accounting rules, total capitalized costs are limited to a ceiling 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 unproved properties less income tax effects (the ceiling limitation). We perform a quarterly ceiling test to evaluate whether the net book value of our full cost pool exceeds the ceiling limitation. If capitalized costs (net of accumulated depreciation, depletion and amortization) less related deferred taxes are greater than the discounted future net revenues or 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 and as adjusted for basis or location differentials, held constant over the life of the reserves. 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 March 31, 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.

Unevaluated Properties. The costs associated with unevaluated properties and properties under development 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 interest costs capitalized 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 wells pending determination 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. 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 our Texas Gulf of Mexico assets on March 31, 2006, unevaluated properties were reduced by approximately $31.4 million.

Asset Retirement Obligations

The following table describes changes in our ARO liability during each of the three-month periods ended March 31, 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.

Three Months Ended March 31,

	2006	2005
	(in thousands)	
ARO liability at January 1,	$ 119,671	$ 91,746
Accretion expense	1,327	1,325
Liabilities incurred from drilling	1,849	1,449
Liabilities settled assets sold	(30,795)	
Changes in estimates	(76)	798
ARO liability at March 31,	$ 91,976	$ 95,318

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

Derivative Instruments and Hedging Activities

Our derivative instruments are not held for trading purposes. Further, our hedging policy prescribes that at the time we enter into any derivative contract, such contract must meet the requirements for hedge accounting under SFAS 133 and must be specifically identified as a hedge for federal income tax purposes as defined in Section 1221(b)(2) of the Internal Revenue Code. Our hedging policy also allows us the flexibility 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 New York Mercantile Exchange (NYMEX) prices, as opposed to the index price where the gas is actually sold, our hedging strategy may not fully protect our cash flows when, as in recent quarters, the price differential increases between the NYMEX price and index price for the point of sale.

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 forecasted 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 no longer qualify for hedge accounting. Mark-to-market accounting is then utilized. Amounts 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 they 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.

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 on the NYMEX price, combined with an increase in the natural gas supply in the mid-continent region due in part to a warm winter and pipeline expansions in the region. On February 28, 2006, we entered 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*). Upon entering into this agreement, the forecasted production volume attributable to these properties was deemed no longer available to cover open hedge positions. Because of the method we utilized prior to February 28, 2006 to allocate hedged production, the remaining portion of all our open derivative contracts that previously qualified for hedge accounting ceased to qualify for hedge accounting. As a result, all subsequent changes in the fair market value of these open contracts will be recognized in income as either a gain or loss.

At March 31, 2006, an unrealized loss of $97.4 million, net of tax, remains deferred in accumulated other comprehensive income. This loss represents the fixed value of our remaining open derivative contracts at the time they ceased to qualify for hedge accounting. With the exception of (i) that portion of our contracts relating to Texas Gulf of Mexico production for which all previously deferred losses were completely reclassified from accumulated other comprehensive income to earnings in the first quarter of 2006 and (ii) all amounts relating to Louisiana Gulf of Mexico production that will be reclassified upon the sale of the Louisiana Gulf of Mexico assets expected to occur during the second quarter of 2006, all remaining deferred losses will be reclassed 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 $77.7 million, net of tax, with $19.7 million to be recognized thereafter. However, these amounts could vary materially as a result of changes in market conditions.

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

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 the 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 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 months ended March 31, 2005:

	Three Months Ended March 31, 2005 (in thousands)
Net income as reported	$ 33,438
Add: Stock-based compensation expense included in net income, net of tax	446
Less: Stock-based compensation expense determined using fair value method, net of tax	(802)
Net income pro forma	$ 33,082
Net income per share basic as reported	$ 1.17
Net income per share diluted as reported	1.16
Net income per share basic pro forma	$ 1.16
Net income per share diluted pro forma	1.15

The weighted average fair value of options granted and the valuation assumptions used in the Black-Scholes option-pricing model during the three months ended March 31, 2006 and 2005 are as follows:

	Three Months Ended March 31, 2006	2005
Weighted average fair value of options granted	$ 12.28	$ 21.43
Risk-free interest rate	4.55%	3.97%
Expected years until exercise	3	5
Expected stock volatility	25.6%	35.6%
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 daily rates for either five-year or three-year United States treasury bills with constant maturity that correspond to the option s vesting period. 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 36-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.

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

The following table provides the detail of stock compensation expense incurred during each of the three-month periods ended March 31, 2006 and 2005:

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
	(in thousands)	
Options	$ 1,687	$ 817
Restricted stock	830	195
Stock compensation expense, gross	2,517	1,012
Amounts capitalized	(746)	(322)
Stock compensation expense, net of amounts capitalized	$ 1,771	$ 690

At March 31, 2006, our unrecognized stock compensation expense related to unvested stock options to be recognized over the next four-year period is approximately $13.7 million. At March 31, 2006, unearned compensation expense related to restricted stock and expected to be recognized over the next four-year period totaled $7.6 million and is included as a component of additional paid-in capital.

Stock and Option Plans

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 the 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 the stockholders in May 2002 and amended by our Board in October 2003; and (iv) the 2004 Long-Term Incentive Plan, approved by the 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, with the exception of executive officers who are not eligible to participate in the 1999 plan. The 1996, 2002 and 2004 plans allow for the grant of both incentive stock options and non-qualified stock options and the 2002 and 2004 plans allow for the grant of restricted stock. Pursuant to 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, with a limit of 300,000 shares for restricted stock grants, under the 2004 plan. At March 31, 2006, we had 657,128 shares authorized and available for awards 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, with the exception of options granted to directors whose options 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 grants are made at 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 grants of non-qualified stock options and 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 the exercise of stock-based compensation as cash flow from operating activities within our consolidated statements of cash flows. SFAS 123(R) requires the excess of the tax benefits to be presented as cash in-flow from financing activities.

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The following table below summarizes the activity for stock options for the three months ended March 31, 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	36,950	52.53		
Exercised	(84,844)	38.06		
Forfeited	(15,830)	44.51		
Options outstanding March 31	1,632,886	$ 40.19	6.8	$ 20,427
Options exercisable March 31, 2006	600,869	$ 32.73	5.7	$ 11,999

(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: market price at the end of the period less the exercise price.

Restricted Stock. Restricted stock may be granted and issued to executive officers, employees, non-employee directors and affiliated directors as a component of each recipient s annual compensation and vesting is 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.

	Restricted Shares	Weighted Average

	(shares)	Grant Price ($/share)
Unvested restricted stock January 1, 2006[1]	171,214	$ 56.23
Granted	12,500	54.40
Vested		
Forfeited	(2,362)	58.88
Unvested restricted stock March 31, 2006	181,352	$ 55.93

(1) Includes 52,501 units granted in July 2005 pursuant to a retention bonus plan 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 restricted stock at the end of the vesting period and 50,139 units under the retention bonus plan were unvested and outstanding at March 31, 2006.

NOTE 2 Long-Term Debt and Notes

	March 31, 2006	December 31, 2005
	(in thousands)	
Senior Debt:		
Revolving credit facility, due November 30, 2010	$ 249,000	$ 422,000
Subordinated Debt:		
7% senior subordinated notes, due June 15, 2013.	175,000	175,000

Total long-term debt and notes	$ 424,000	$ 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 March 31, 2006, the quoted market value of our $175 million of 7% senior subordinated notes was 97.6% of the $175 million carrying value, or $171 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.

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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. Effective April 1, 2006, and in connection with the sale of the Texas portion of our Gulf of Mexico assets on March 31, 2006, our borrowing base of $600 million was reduced by $50 million to $550 million. We expect our borrowing base to be further reduced upon closing of the pending sale of our Louisiana Gulf of Mexico assets (see Note 7 Subsequent Events *Pending Sale of Louisiana Gulf of Mexico Assets*). Up to $60 million of the borrowing base is available for the issuance of letters of credit. Outstanding borrowings under the revolving credit facility are secured by our onshore 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 facility matures on November 30, 2010. On March 31, 2006, we used a portion of the proceeds received from the sale of our Texas Gulf of Mexico assets to repay and reduce outstanding borrowings under the facility by $158 million. At March 31, 2006, we had $249 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

- not hedge more than 85% of our production during any calendar year.

At March 31, 2006 and December 31, 2005, we were in compliance with all covenants.

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, beginning December 15, 2003. 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. In addition, at any time prior to June 15, 2006, we may redeem up to a maximum of 35% of the aggregate principal amount with the net proceeds of one or more equity offerings at a price equal to 107% of the principal amount, plus accrued and unpaid interest and liquidated damages, if any. The notes are general unsecured obligations and rank subordinate in right of payment to all 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.

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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.

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 March 31, 2006 and December 31, 2005, we were in compliance with all covenants.

NOTE 3 Stockholders Equity

Stock Repurchase Program

In November 2005, our Board of Directors approved a plan for discretionary repurchases from time to time over twelve months ending in November 2006 of up to $200 million in company stock in conjunction with the possible divesture of all of our Gulf of Mexico assets. These purchases may occur in the open market or in privately negotiated transactions, and will be subject to a number of considerations, including market conditions for our shares, applicable legal requirements, contractual limitations, available cash, competing reinvestment opportunities in the acquisition market for oil and gas assets and other factors. We expect that any stock repurchased under this program will be retired. As of March 31, 2006, no repurchases had been made.

NOTE 4 Commitments and Contingencies

Legal Proceedings

We are involved from time to time in various 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 or results of operations.

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 $1.3 million, $1.9 million, $1.9 million, $1.1 million and $0.6 million, respectively.

Letters of Credit

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

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Drilling Contracts

During the first quarter of 2006, we entered into two 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 and a two-year contract for a rig in the Uinta Basin. Under the terms of the contracts, we are obligated for up to an estimated $20.6 million in fees for use of the rigs during the remaining terms of the contracts.

New Supplemental Executive Retirement Plan

Effective January 1, 2006, we adopted a new Supplemental Executive Retirement Plan (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 Plan. 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.

NOTE 5 Related Party Transactions

Employment Agreements with New 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 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.

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The terms of Mr. Ray s and Ms. Campbell s employment agreements are consistent with the general terms described above. Further, under Mr. Ray s agreement, he will initially receive a base salary of $315,000 and will be entitled to an annual incentive bonus equal to 55% of his base salary. Ms. Campbell will initially receive a base salary of $275,000 and will be entitled to an annual incentive bonus equal to 55% of her salary. 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 purchase 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 preliminary adjustment for operations related to the properties after January 1, 2006, the effective date of the transaction. 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, with the balance of $32.8 million used 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.

East Texas Acquisition

On March 10, 2006, we entered into a definitive purchase and sale agreement with Samson Lone Star Limited Partnership to acquire certain interests in natural gas and oil producing properties, together with acreage located in the Willow Springs Field of Gregg County, Texas, for $22 million in cash, subject to customary closing adjustments. Upon signing the purchase and sale agreement, we paid $2.2 million in cash towards the purchase price, which amount we borrowed under our revolving credit facility and is generally nonrefundable, except upon certain limited circumstances. 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, the effective date of the transaction.

NOTE 7 Subsequent Events

Pending Sale of Louisiana Gulf of Mexico Assets

On April 7, 2006, we entered into a definitive purchase and sale agreement with certain partnerships affiliated with Merit Energy Company, as buyer, to sell substantially all the Louisiana portion of our Gulf of Mexico assets for a purchase price of approximately $590 million in cash, subject to customary closing conditions and purchase price adjustments from the effective date of January 1, 2006. 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. The pending sale does not include 18 of our Louisiana offshore blocks, 16 of which are undeveloped and two of which currently have exploratory wells in progress. The transaction is expected to close on May 31, 2006, subject to customary closing conditions. Certain offshore Louisiana properties that we acquired in October 2003 are subject to a net profits interest that the predecessor owner will be entitled to receive upon completion of our sale of these properties. Subsequent to closing of

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the sale of our Louisiana Gulf of Mexico assets, we expect to make a cash payment to the predecessor owner of between $30 million and $50 million. We expect to fund the net profits payment with proceeds from the sale of the assets.

Completion of East Texas Acquisition

On April 25, 2006, we completed the acquisition of the producing properties and acreage in the Willow Springs Field of Gregg County, Texas from Samson as discussed above in Note 6 *Acquisitions and Dispositions*. At closing, we used cash on hand of $19.1 million to fund the remaining portion of the $21.3 million net purchase price.

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 future production, revenues and expenses to differ materially from our expectations. See Forward-Looking Statements and Other Information at the beginning of this Quarterly Report and Item 1A. Risk Factors in our Annual Report on Form 10-K, as amended for the year ended December 31, 2005 for additional discussion of risks affecting our business.

Overview of Our Business

We are an independent natural gas and oil producer concentrating on growing reserves and production through 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 March 31, 2006, we had operations in five producing regions within the United States: South Texas; the Arkoma Basin of Arkansas and Oklahoma; East Texas; the Uinta and DJ Basins in the Rocky Mountains; and the Gulf of Mexico, which is in the process of being sold.

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 fully engineered on an annual basis 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. 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 upward price movements during the first quarter of 2006 and in each of the preceding years 2005 through 2003, 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*).

We operate as one segment 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 focus our operations onshore. We expect that the plan will be executed over time via a series of steps and /or transactions, including (i) the sale of our Gulf of Mexico assets, which may also include the liquidation of a portion of our 2006 hedge position, and (ii) the redeployment of the net sales proceeds into a variety of opportunities, each aimed at enhancing shareholder value. These opportunities may include onshore acquisitions, debt repayments and up to $200 million in discretionary stock repurchases.

We believe this strategic shift toward focusing our operations onshore will leverage our strength of developing complex, tight or low permeable natural gas reservoirs, while providing flexibility to expand both in our present core onshore areas and other tight gas basins. We anticipate that focusing primarily on onshore operations 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 we plan to continue to realize the benefits of scale by operating the majority of our properties and maintaining a high working interest.

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 sales price was adjusted by $29.2 million for various customary closing items, including revenues received and expenditures made by us, the seller, related to the properties for the period between the effective date of the transaction, January 1, 2006, and the closing date, March 31, 2006. 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, with the balance of $32.8 million used for working capital purposes. 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.

On April 7, 2006, we entered into a definitive purchase and sale agreement to sell substantially all of our Louisiana Gulf of Mexico assets to certain partnerships affiliated with Merit Energy Company for a gross purchase price of approximately $590 million in cash, subject to customary closing conditions and purchase price adjustments from the effective date. At December 31, 2005, proved reserves associated with these assets were estimated at 186.1 Bcfe of natural gas and production associated with these assets accounted for approximately 22% of our 2005 production. The transaction has an effective date of January 1, 2006, and is expected to close on May 31, 2006, subject to customary closing conditions. The purchase and sale agreement with Merit does not include the sale of 18 of our Louisiana offshore blocks, 16 of which are undeveloped and two (West Cameron 39 and 132) of which currently have exploratory wells in progress. In addition, certain offshore Louisiana properties that we acquired in October 2003 are subject to a net profits interest that the predecessor owner will be entitled to receive upon completion of our sale of these properties. Subsequent to closing of the sale of our Louisiana Gulf of Mexico assets, we expect to make a cash payment to the predecessor owner of between $30 million and $50 million. We expect to fund the net profits payment with proceeds from the sale of the assets, and the payment will be added to the full cost pool as an adjustment to the original $147.5 million net purchase price of the properties.

Shift in Our Hedging Strategy. In connection with the completion of our divestiture of our Gulf of Mexico assets, and after taking into account the impact of the sale of these assets on our production levels and any acquisitions that appear imminent at May 31, 2006, the date we expect to close and complete the sale of the Louisiana portion of these offshore assets, we will be required under our revolving credit facility to liquidate a portion of our 2006 hedge position. In order to comply with this requirement, we estimate that we will liquidate open contracts representing the equivalent of approximately 80,000 MMBtu per day of hedged production prior to closing of the sale of our Louisiana offshore assets expected to occur on May 31, 2006. Depending on prices in effect at the time of liquidation, we could be required to make a payment to unwind and settle these open contracts, which payment we would expect to finance with proceeds from the sale of our Gulf of Mexico assets and/or borrowings under our revolving credit facility. Based on prices in effect as May 9, 2006, we estimate the cost to unwind and settle these open contracts could be between $20 million and $25 million.

After the expected unwinding and settlement of these open contracts, our open hedge position for the remaining months of 2006 (June through December) will decrease from 250,000 MMBtu per day to the equivalent of 170,000 MMBtu per day. We currently have open hedge 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 13% of our expected production rate at December 31, 2006. Based on the current commodity price environment, we do not expect to enter into additional derivative contracts at this time. However, we continue to evaluate opportunities to hedge our basis differential and may elect to hedge a portion of that exposure if market conditions warrant.

Redeployment of Net Sales Proceeds. We intend to pursue a balanced and disciplined approach to the redeployment of the 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. These opportunities may include the development of our existing onshore assets, as well as the pursuit of additional opportunities onshore. We expect to be disciplined in our approach, targeting only those opportunities that deliver clear strategic and financial benefits as measured by our internal rate of return and accretion metrics. Further, we expect to maintain a strong balance sheet throughout our redeployment process. Given that our business is capital intensive, exposed to commodity price swings and cycles, and characterized by a declining asset base, we believe that maintaining financial flexibility and access to

capital is very important.
Since our offshore assets accounted for 40% of our 2005 production and represented approximately 245 Bcfe, or 28% of our proved reserves, at December 31, 2005, our operating revenues and cash flows are expected to decrease following the sale of these offshore assets. There can be no assurance that we will be able to replace this sold production via the acquisition of new properties on attractive terms. Our plans also include structuring any such acquisitions, where prudent, as tax-free exchanges under Section 1031 of the Internal Revenue Code. However, market conditions, inherent acquisition risks and other uncertainties may not allow for the reinvestment of all of the proceeds within the prescribed time period for

the most tax-efficient results or at all. If we are unable to identify acquisitions that we believe warrant our investment, then we intend to explore other options for allocating our capital. In addition to acquiring longer-lived natural gas assets onshore in North America, we also expect to use a portion of the proceeds from the sale of our Gulf of Mexico assets to repay existing bank debt and fund discretionary open market or privately negotiated repurchases from time to time of up to $200 million in common stock of the company.

Recent Acquisition

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 revenues received by and expenditures made by the seller related to the properties for the period between the effective date of the transaction, January 1, 2006, and the closing date, April 25, 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 effective date of the transaction. 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.

Overview of Results for the First Quarter of 2006

Continued strong commodity prices, a decline in average daily production and an increase in operating expenses were the primary factors behind results of operations, earnings and cash flows during the first three months of 2006. We continued to implement our restructuring plan to focus our operations primarily onshore, as we completed the sale of the Texas portion of our Gulf of Mexico assets on March 31, 2006 and, subsequently on April 7, 2006, entered into an agreement to sell substantially all of the Louisiana portion of our Gulf of Mexico assets. Our results of operations for the first three months of 2006 include production, revenues and expenses relating to the Texas Gulf of Mexico properties sold, as the transaction was completed on March 31, 2006, with an effective date of January 1, 2006.

During the first quarter of 2006:

- We generated $29.8 million in net income, a decrease of 11% from $33.4 million in the first quarter 2005, due primarily to continued lower production volumes resulting from Hurricanes Katrina and Rita. Specifically, we estimate deferred production for the first three months of 2006 of approximately 3.1 Bcfe or 34 MMcfe/day, impacting revenues for the quarter by an estimated $26.3 million;

- We produced approximately 28 Bcfe and our average daily production rate was 312 MMcfe per day compared to 285 MMcfe per day during the fourth quarter of 2005 and 331 MMcfe per day during the first quarter of 2005, a 9% increase from the previous quarter and a 6% decrease from a year ago;

- We generated $122.5 million in net cash flows from operating activities compared to $133.3 million during the first quarter of 2005, a decrease of 8% primarily as a result of lower operating income;

We decreased net borrowings under our revolving credit facility by $173 million, using proceeds from the sale of our Texas Gulf of Mexico assets to repay $158 million and cash generated from operations to repay $15 million;

We invested $122.9 million in natural gas and oil properties compared to $146.3 million during the first quarter of 2005, a decrease of 16%, as we began implementing our strategy to focus our operations onshore which has been historically less capital intensive than offshore;

We drilled 73 wells, of which 65, or 89%, were successful, with six in East Texas, 14 in South Texas, 20 in Arkoma and 25 in the Rockies;

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In South Texas, we continued to integrate the producing properties acquired at the end of November 2005, acquired a 3D seismic survey covering approximately 1,000 square miles in the Vicksburg trend, added a seventh drilling rig and prepared to spud our first well in Tijerina-Canales-Blucher Field in mid-April 2006; and

In the Rockies, we completed a 150 square mile 3D seismic survey in the DJ Basin, started up the second phase of our DJ Basin gathering system, brought over 45 newly completed wells on-line to the system, and expanded our acreage position in Utah, adding approximately 4,250 net acres.

Subsequent to March 31, 2006:

Effective April 1, 2006 and in connection with the completion of the sale of the Texas portion of our Gulf of Mexico assets on March 31, 2006, the borrowing base on our revolving credit facility was reduced by $50 million, from $600 million to $550 million;

On April 7, 2006, we entered into a definitive purchase and sale agreement with certain partnerships affiliated with Merit Energy Company, as buyer, to sell substantially all of our Louisiana Gulf of Mexico assets for a purchase price of approximately $590 million in cash, subject to customary closing conditions and purchase price adjustments. The sale is expected to close on May 31, 2006, with an effective date of January 1, 2006 (see Note 7 Subsequent Events *Pending Sale of Louisiana Gulf of Mexico Assets*);

On April 25, 2006, we acquired producing properties and acreage with an estimated 16.2 Bcfe of proved reserves as of January 1, 2006, from Samson Lone Star Limited Partnership for a net purchase price of $21.3 million. The properties are located in the Willow Springs Field of Gregg County, adjacent to our existing East Texas operations (see Note 6 Acquisitions and Dispositions *East Texas Acquisition*); and

On May 4, 2006, we announced our capital expenditure budget for 2006 of $521 million, of which we plan to spend $443 million onshore for exploration and development, $53 million offshore and $25 million for capitalized interest and general and administrative expenses.

Operating and Financial Results for the Three Months Ended March 31, 2006 Compared to the Three Months Ended March 31, 2005.

	Three Months Ended March 31,			
	2006	**2005**	**Variance**	
	(in thousands, expect percentages and price data)			
Summary Operating Information:				
Natural gas revenues	$198,505	$163,969	$ 34,536	21%
Oil revenues	20,453	17,120	3,333	19%
Gain (loss) on settled derivatives	(46,525)	(14,175)	(32,350)	228%
Unrealized gain (loss) derivatives	4,586	(1,424)	6,010	-422%
Operating revenues	177,604	165,720	11,884	7%
Operating expenses	124,436	104,119	20,317	20%
Income from operations	53,168	61,601	(8,433)	-14%
Net income	29,772	33,438	(3,666)	-11%
Production:				
Natural gas (MMcf)	26,023	27,357	(1,334)	-5%
Oil (MBbls)	348	406	(58)	-14%
Total (MMcfe) [1]	28,111	29,793	(1,682)	-6%

Average daily production (MMcfe/d)	312	331	(19)	-6%
Average Sales Prices:				
Natural Gas (per Mcf) unhedged	$ 7.63	$ 5.99	$ 1.64	27%
Natural Gas (per Mcf) realized [2]	5.84	5.48	0.36	7%
Natural Gas (per Mcf) all-in [3]	6.02	5.42	0.60	11%
Oil (per Bbl) realized	58.77	42.17	16.60	39%

(1) Mcfe is defined as one thousand cubic feet equivalent of natural gas, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

(2) Average prices include gains and losses realized on derivative contracts settled during the period.

(3) Average prices include 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.

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Income from Operations

Operating revenues were 7% higher during the first quarter of 2006 as compared to the first quarter 2005 primarily as a result of an 11% increase in average all-in natural gas prices offset in part by a 6% decrease in equivalent production volumes. While higher market prices for natural gas during the first quarter of 2006 caused our losses from hedging activities to increase from first quarter 2005, our losses from hedging activities narrowed considerably from the fourth quarter of 2005 due to the sharp decline in natural gas prices from the record highs seen during the fourth quarter of 2005. Income from operations for the first quarter of 2006 decreased by $8.4 million, or 14%, as compared to the first quarter of 2005, as the 20% increase in operating expenses, primarily due to rising service costs, severance and depreciation, depletion and amortization expenses, more than offset the 7% increase in operating revenues for the first quarter of 2006.

Production Volume

Production volumes were 6% lower during the first quarter of 2006 compared to the first quarter of 2005. The following table provides a comparison of average daily production by area:

	Three Months Ended March 31,			
Average Daily Production by Area:	**2006**	**2005**	**Variance**	
	(Natural Gas Equivalents	MMcfe)		
South Texas	145	135	10	7%
Arkoma	40	43	(3)	-7%
East Texas	11	2	9	+100%
Rockies	6	5	1	20%
Other		2	(2)	-100%
Total onshore	202	187	15	8%
Offshore	110	144	(34)	-24%
Total company	312	331	(19)	-6%

Onshore. Daily production rates increased by 15 MMcfe per day, or 8%, from an average of 187 MMcfe per day during the first quarter of 2005 to an average of 202 MMcfe per day during the first quarter of 2006.

In South Texas, we added approximately 10 MMcfe per day, primarily from the properties acquired at the end of November 2005 from Kerr-McGee and Westport. In Arkoma, average daily production declined approximately 3 MMcfe per day due to a partial curtailment of our drilling activity late in the third quarter of 2005 as one of our drilling rigs left the field for repair. In January 2006, the rig returned to the field, where we currently have three rigs drilling. In East Texas, the 9 MMcfe per day increase from the first quarter of 2005 is due to our acquisition of acreage and producing wells during 2005 combined with the drilling program initiated in the second quarter of 2005 that added 16 new producing wells during 2005. This successful developmental drilling program continued into the first quarter of 2006 with the addition of six successful wells. In the Rockies, we continue to make progress even as we await new well connections, as average daily production increased by 20%, primarily as a result of newly developed production in the DJ Basin.

Offshore. Daily production decreased by 24%, or 34 MMcfe per day, from an average of 144 MMcfe per day during the first quarter of 2005 to an average of 110 MMcfe per day during the first quarter of 2006. During the first quarter of 2006, we continued to experience hurricane-related curtailments as a result of the damage to third party pipelines and facilities. We estimate that approximately 34 MMcfe per day was curtailed and deferred during the first quarter, primarily at Eugene Island 331 and Vermilion 369 and 408.

Commodity Prices and Effects of Hedging

During the fourth quarter of 2005 and the first quarter of 2006, a portion of our derivative contracts became ineffective as hedges. In conjunction with our entry into an agreement on February 28, 2006 to sell our Texas Gulf of Mexico assets, forecasted production volume attributable to these properties was deemed no longer available to cover open hedge positions and, because of the method we utilized to allocate hedged production, the remaining portion of all our open derivative contracts that previously qualified for hedge accounting ceased to qualify for hedge accounting. As a result, applicable accounting guidelines precluded our use of hedge accounting for all open derivative contracts at the end of the first quarter of 2006. Accordingly, mark-to-market accounting is now utilized and all subsequent changes in the fair value of open derivative contracts will be recognized as an increase or reduction to natural gas revenues. The following table summarizes the components of our realized and unrealized gains and losses due to hedging activities

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for the three months ended March 31, 2006 and 2005. All amounts in the following table are pre-tax and included in the line item natural gas and oil revenues.

	Three Months Ended March 31,	
	2006	2005
	(in thousands)	
Cash (loss) realized on contracts settled	$ (46,525)	$ (14,175)
Non-cash unrealized gain (loss):		
Ineffectiveness gain (loss)	15,790	(1,424)
Mark-to-market change in fair value gain (loss)	38,166	-
Deferred loss prior quarter production shortfalls	(20,600)	-
Reclass of all deferred losses relating to Texas Gulf of Mexico production sold during quarter	(28,770)	-
Total non-cash unrealized gain (loss)	4,586	(1,424)
Total gain (loss) from hedging activities	$ (41,939)	$ (15,599)

For the three months ended March 31, 2006, our average unhedged sales price for natural gas increased by 27% from $5.99 per Mcf during the first quarter of 2005 to $7.63 per Mcf during the first quarter of 2006. Because of the increase in the market price for natural gas, our total loss from hedging activities increased by $26.3 million quarter-over-quarter. Included in natural gas revenues for the first quarter of 2006 is a net loss of $41.9 million from natural gas hedging activities, which includes a realized loss of $46.5 million relating to contracts settled during the period and a net unrealized gain of $4.6 million as a result of accounting under SFAS 133. As a result of the cash loss from derivative contracts settled during the first quarter of 2006, we realized an average natural gas price during the quarter of $5.84 per Mcf, which was 23% lower than our average unhedged sales price of $7.63 per Mcf. During the first quarter of 2005, we incurred a total loss from hedging activities of $15.6 million, which included a realized loss on derivative contracts settled of $14.2 million and an unrealized loss of $1.4 million as a result of the ineffectiveness of our open contracts accounted for as cash flow hedges under SFAS 133. As a result of the cash loss from hedge contracts settled during the first quarter of 2005, we realized an average price of $5.48 per Mcf, which was 9% lower than our average unhedged sales price of 5.99 per Mcf.

Operating Expenses

	Three Months Ended March 31,			
Operating Expenses per Mcfe	**2006**	**2005**	**Variance**	
Lease operating expense	$0.78	$0.52	$ 0.26	50%
Severance tax	0.22	0.10	0.12	120%
Transportation expense	0.10	0.09	0.01	11%
Asset retirement accretion expense	0.05	0.04	0.01	25%
Depreciation, depletion and amortization	2.98	2.37	0.61	26%
General and administrative, net	0.31	0.37	(0.06)	-16%
Total operating expenses per unit of production	$4.44	$3.49	$ 0.95	27%

Total operating expenses on an absolute dollar basis increased 20% for the first quarter of 2006 as compared to the first quarter of 2005, primarily as a result of higher lease operating expenses, severance tax expense and depreciation, depletion and amortization expense. On a unit of production basis, operating expenses increased $0.95 per Mcfe, or 27%, quarter-over-quarter. Per unit expenses were higher for all categories of operating expense due to the continued curtailment of offshore production, combined with the effect of higher costs.

Lease Operating Expense. On an absolute dollar basis, lease operating expense increased by 42% for the first quarter of 2006 as compared to the first quarter of 2005. The increase during the first three months of 2006 relates primarily to the continued upward pressure on service costs, labor, materials, insurance and property taxes resulting from the sustained strength of commodity prices that is driving increased activity level across the industry, combined with the continued expansion of our operating base from acquisitions and the escalation of our drilling program.

Severance Tax. Severance tax is a function of volumes and revenues generated from onshore production. During the first quarter of 2006, severance tax expense increased by 110% on an absolute dollar basis and by $0.12 per Mcfe on a unit of production basis from the first quarter 2005. These absolute dollar and per unit rate increases reflect higher commodity prices, an increase in severance tax rates and an increase in onshore production, due in part to the South Texas properties acquired in November 2005. We expect our severance tax per unit of production to increase considerably following the divesture of all our offshore production.

Depreciation, Depletion and Amortization. The increase in our depreciation, depletion and amortization expense for the three months ended March 31, 2006 was primarily a result of a higher depletion rate, offset in part by lower production volumes. Our depreciation, depletion and amortization rate for the first quarter of 2006 was $2.98 per Mcfe, or 29% higher than the $2.37 per Mcfe during the first quarter of 2005, and was $0.07 per Mcfe lower than our depreciation, depletion and amortization rate of $3.05 per Mcfe during the fourth quarter of 2005. Sequentially, from fourth quarter 2005 to first quarter 2006, the decline in the rate is due to the effects of the disposition of our Texas Gulf of Mexico assets during the first quarter of 2006. The higher rate for first quarter 2006 compared to first quarter 2005 is a result of the increase in our finding and future development costs.

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

	Absolute Dollars				Unit of Production Mcfe			
	Three Months Ended March 31,				Three Months Ended March 31,			
General and Administrative Expense	**2006**	**2005**	**Variance**		**2006**	**2005**	**Variance**	
	(in thousands)							
Gross general and administrative expense	$ 14,398	$ 15,962	$ (1,564)	-10%	$ 0.51	$ 0.53	$ (0.02)	-4%
Operating overhead reimbursements	(598)	(550)	(48)	9%	(0.02)	(0.02)		
Capitalized general and administrative	(5,194)	(4,289)	(905)	21%	(0.18)	(0.14)	(0.04)	29%
General and administrative expense, net	$ 8,606	$ 11,123	$ (2,517)	-23%	$ 0.31	$ 0.37	$ (0.06)	-16%

Gross and net general and administrative expenses were higher during the first quarter of 2005 as compared to the first quarter of 2006 as we incurred additional expenses of approximately $5.0 million in the prior year pursuant to the February 2005 renegotiation of executive employment agreements. Excluding the $5.0 million in additional expenses incurred during the first quarter of 2005, both gross and net general and administrative expenses would have increased by $3.4 million, or 31%, and $2.5 million, or 41%, respectively, from the first quarter of 2005 to the first quarter of 2006. These increases are due primarily to an increase in salaries, benefits and incentive compensation expenses, stock compensation expense and outside legal and consulting fees. Capitalized general and administrative expense increased during the first three months of 2006 primarily as a result of the increase in salaries, benefits and incentive compensation expenses for our technical workforce.

On a per-unit of production basis, the additional $5.0 million in general and administrative expenses incurred during the first quarter of 2005 in connection with the renegotiation of executive employment agreements resulted in a $0.17 per Mcfe increase during the first quarter of 2005. Excluding the $0.17 per Mcfe from first quarter 2005 results, gross and net general and administrative expense would reflect a $0.15 per Mcfe, or 42%, increase and $0.11 per Mcfe, or 55%, increase, respectively, from first quarter 2005 to first quarter 2006. These increases reflect a 31% increase in gross expenses combined with a 6% decrease in production volume for the period.

Other Income and Expense, Interest and Taxes

Other Income and Expense. For the first quarter of 2006, other income and expense is comprised of income of $1.4 million related to refunds of prior years severance tax expense. For the first quarter of 2005, other income and expense includes (i) income of $1.3 million related to refunds of prior years severance tax expense and (ii) expense of $2.8 million incurred as a result of 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%. 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.

Interest Expense, Net of Capitalized Interest

Interest and Average Borrowings	Three Months Ended March 31, 2006	2005	Variance	
	(dollars in thousands)			
Gross interest	$ 10,376	$ 5,424	$ 4,952	91%
Capitalized interest	(1,655)	(1,990)	335	17%
Interest expense, net of capitalized interest	$ 8,721	$ 3,434	$ 5,287	154%
Average total borrowings [(1)]	$ 619,000	$ 345,000	$ 274,000	79%
Average total interest rate [(1)]	6.47%	5.82%	0.65%	11%
Average bank borrowings	$ 444,000	$ 170,000	$ 274,000	161%
Average bank interest rate	6.26%	4.60%	1.66%	36%

(1) Average total borrowings and average total interest rate includes our $175 million senior subordinated notes at 7% due June 2013 and average borrowings under our revolving credit facility.

For the three months ended March 31, 2006, the increase in gross interest expense is due to an increase in outstanding borrowings under our revolving credit facility combined with an increase in average interest rates associated with our bank debt. Our average bank debt increased after the first quarter of 2005 as we utilized bank borrowings to fund acquisitions in East Texas and South Texas and to settle obligations under derivative contracts. 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 twice during the first quarter of 2006. We expect to continue to see an increase in the average interest rates we pay on our bank debt if the Federal Reserve continues to increase Federal interest rates. Capitalized interest is a function of unevaluated properties, and the 17% decrease for the first quarter of 2006 as compared to the first quarter of 2005 corresponds to a decrease in the balance of our unevaluated properties, primarily as a result of the sale of our Texas Gulf of Mexico assets.

Liquidity

Capital Requirements

Our principal requirements for capital are to fund our exploration, development and acquisition activities and to satisfy our contractual obligations, primarily including the repayment of debt and any amounts owing during the period relating to our derivative contracts. Our uses of capital 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

Indirect costs related to our exploration activities, including payroll and other expenses attributable to our exploration professional staff.

For 2006, we have established a capital budget of $521 million. As of March 31, 2006, we had spent approximately 24%, or $123.1 million, of our 2006 budget. To maintain 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 an opportunity is economically beneficial. See Note 4 Commitments and Contingencies *Drilling Contracts*. As the year progresses, we will continue to evaluate our capital spending. Actual spending levels may vary due to a variety of factors, including the timing of the completion of the sale of our Gulf of Mexico assets, drilling results, natural gas prices, economic conditions and future acquisitions.

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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 March 31, 2006. All amounts listed in the following table are categorized as liabilities on our balance sheet with the exception of lease payments for operating leases, obligations under long-term drilling contracts, outstanding letters of credit issued for performance obligations and the remaining portion of the purchase price of the East Texas properties acquired in April 2006. At March 31, 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.

In addition to the contractual obligations listed on the following table, our balance sheet at March 31, 2006 reflects accrued interest payable on our revolving credit facility of approximately $0.3 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. As a result of credits and amounts on deposit that were paid during 2005, we do not expect to make any cash payments for federal income taxes during 2006 and expect to pay less than $1.0 million for state income taxes.

In connection with the pending sale of substantially all of our Louisiana Gulf of Mexico assets and pursuant to requirements under our revolving credit facility, prior to June 30, 2006, we plan to liquidate certain of our derivative contracts allocated to offshore production. We estimate, based on prices in effect on May 9, 2006, that we could be required to make a payment of between $20 million and $25 million to unwind and settle these contracts. We would expect to fund the settlement of these contracts with a portion of the proceeds from the sale of the related Louisiana Gulf of Mexico assets and/or borrowings under our revolving credit facility. In addition, certain offshore Louisiana properties that we acquired in October 2003 are subject to a net profits interest that the predecessor owner will be entitled to receive upon completion of our sale of these properties. Subsequent to closing of the sale of our Louisiana Gulf of Mexico assets, we expect to make a cash payment to the predecessor owner of between $30 million and $50 million. We expect to fund the net profits payment with proceeds from the sale of the assets.

			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	$ 249,000	$	$	$ 249,000	$
7% senior subordinated notes, due June 2013	Note 2	175,000				175,000
Derivative instruments	Note 1	149,450	103,080	46,370		
East Texas acquisition, remaining purchase price	Note 7	20,000	20,000			
Operating leases	Note 4	6,230	1,350	3,763	1,117	
Letters of credit	Note 4	300	300			
Drilling contracts	Note 4	20,553	13,548	7,004		
		620,533	138,278	57,137	250,117	175,000

Other Long-Term Obligations:						
Asset retirement obligations	Note 1	85,009	6,905	17,531	13,469	47,104
Supplemental Executive Retirement Plan	Note 4	2,229	100	265	261	1,603
		87,238	7,005	17,796	13,730	48,707
Total contractual obligations and Commitments:		$ 707,771	$ 145,283	$ 74,933	$ 263,847	$ 223,707

Capital Resources

We intend to fund our contractual commitments noted above, including any required settlement of derivative contracts, as well as our capital expenditure program, including any future acquisitions, with cash flows from our operations and borrowings under our revolving credit facility. In addition, we expect to use the proceeds from the sale of our Louisiana Gulf of Mexico assets for one or more of the following purposes: acquiring additional onshore assets, repaying indebtedness and/or repurchasing shares of our common stock.

At March 31, 2006, and after taking into account the reduction of our borrowing base from $600 million to $550 million following the sale of our Texas Gulf of Mexico assets, we had $300.7 million of available borrowing capacity under our revolving credit facility. Upon completion of the pending sale of our Louisiana Gulf of Mexico assets, which is scheduled to close on May 31, 2006, we expect that our borrowing base will be further decreased. If a significant acquisition opportunity arises, we may also choose to access the public capital markets to issue additional debt and/or equity securities. Our primary sources of cash during the first three months of 2006 were from funds generated from operations, bank borrowings and proceeds from the sale of the Texas portion of our Gulf of Mexico assets. Cash was used primarily to repay bank borrowings, fund exploration and development expenditures and fund the required settlements of derivative contracts. During the first three months of 2006, we made aggregate cash payments of $6.9 million for interest and no cash payments for taxes. The table below summarizes the sources of cash for the three months ended March 31, 2006 and 2005:

	Three Months Ended March 31,		
	2006	**2005**	**variance**
		(in thousands)	
Net cash provided by operating activities	$ 122,121	$ 133,359	$ (11,238)
Net cash provided by (used in) investing activities	58,780	(130,988)	189,768
Net cash (used in) financing activities	(169,342)	(7,188)	(162,154)
Net increase (decrease) in cash	$ 11,559	$ (4,817)	$ 16,376

At March 31, 2006, we had a working capital deficit of $48.9 million and long-term debt of $424 million. The working capital deficit at March 31, 2006 was due to a current liability of $103.1 million representing the fair value of our derivative instruments estimated to be payable over the next 12 months, offset in part by the associated deferred tax asset of $29.5 million. Due in part to the settlement of open contracts during the first three months of 2006 and in part to a decline in the market price for natural gas from December 31, 2005 to March 31, 2006, the fair value of our open derivative contracts payable within the next 12 months decreased by $249.4 million from a liability of $352.5 million at December 31, 2005, to a liability of $103.1 million at March 31, 2006. Corresponding to the decrease in the current derivative liability, the associated deferred tax asset decreased by $105.0 million during the same three-month period. NYMEX prices declined considerably during the first three months of 2006 from the closing price of $11.431 per MMBtu for the January 2006 contract to $7.233 per MMBtu for the April 2006 contract. The fair value of our derivative instruments will fluctuate with commodity prices, and as commodity prices increase, our liquidity exposure tends to increase as a result of open derivative instruments. Consequently, we are more likely to have a larger unfavorable mark-to-market position in a higher commodity price environment. Our working capital balance fluctuates as a result of the timing and amount of cash receipts and disbursements for operating activities 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.

Operating Activities. Net cash provided by operating activities decreased by $11.2 million or 8% during the first three months of 2006. The decrease was primarily a result of the 14% decrease in operating income during the first quarter of 2006 as compared to the first quarter of 2005. In addition to fluctuations in operating assets and liabilities that are caused by timing of cash receipts and disbursements, commodity prices, production volume and operating expenses are the key factors driving changes in operating cash flows. During the first three months of 2006, we realized higher commodity prices and lower production volumes, together with higher operating expenses compared to the same three-month period of 2005.

Investing Activities. Total company capital expenditures during the first three months of 2006 were $123.1 million, which excludes the non-cash change in exploration and development costs accrued and unpaid of $7.4 million. During the first three months of 2006, we spent $23.5 million, or 16% less than we spent during the first three months of 2005 on natural gas and oil capital expenditures. During the first three months of 2006, we invested a net $122.9 million in natural gas and oil properties, which includes $2.2 million a pending East Texas acquisition of producing properties, and we spent $0.2 million for non-oil and gas property and equipment. Non-oil and gas property and equipment includes expenditures to upgrade to our information technology systems and office equipment and compares to

$0.3 million spent during the first three months of 2005. During the first three months of 2006, we spent 73% onshore and 21% offshore with the balance of 6% on capitalized interest and general and administrative costs. We completed the drilling of 73 gross wells (57.0 net), of which 89%, or 65 (51.1 net), were successful and 8 (5.9 net) were unsuccessful, with an additional 27 wells (16.4 net) in progress at the end of the quarter. All wells drilled during the first three 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 in progress at the end of the quarter. For the first quarter of 2006, investing activities includes net proceeds from the sale of the Texas portion of Gulf of Mexico assets totaling $189.4 million, of which we used $158 million to repay borrowings under our revolving credit facility, with the balance used for working capital purposes.

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	March 31, 2006	March 31, 2005
	(in thousands)	
Natural gas and oil capital expenditures		
Producing property acquisitions[(1)]	$ (1,891)	$ 22,615
Leasehold and lease acquisition costs[(2)]	18,879	25,237
Development	89,668	73,223
Exploration	16,277	25,239
Total natural gas and oil capital expenditures	122,933	146,314
Producing property dispositions[(3)]	(189,371)	(150)
Net natural gas and oil capital expenditures	$ (66,438)	$ 146,164

(1) For the three months ended March 31, 2006, includes the following: (i) deposit of $2.2 million paid for producing properties in East Texas which acquisition closed in April 2006; and (ii) a final purchase price adjustment and return of capital of $4.1 million representing a reduction to the $159.0 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 March 31, 2006 and 2005, includes capitalized interest and general and administrative expenses of $6.8 million and $6.3 million, respectively.

(3) For the three months ended March 31, 2006, includes proceeds from the sale of our Texas Gulf of Mexico assets of $190.8 million, net of $1.5 million in fees associated with completion of the transaction.

Financing Activities. During the first three months of 2006, total long-term debt decreased by a net $173 million as we used $158 million of the proceeds received from the sale of our Texas Gulf of Mexico assets to repay bank borrowings, with the balance, of $15 million, in repayments coming from cash generated from operating activities.

Access to Capital Markets. 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.

We believe that operating cash flow and our credit facility will be adequate to meet our capital and operating requirements during the remaining nine months 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. Our revolving credit 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 effective April 1, 2006 was reduced by $50 million to $550 million in connection with the completion of the sale of the Texas portion of our offshore assets. We expect our $550 million borrowing base to be further reduced upon closing of the pending sale of our Louisiana offshore assets, which is scheduled to occur on May 31, 2006. In addition to operating cash flow and borrowings under our revolving credit facility, we believe we could finance a substantial portion of any additional required capital expenditures with issuances of additional debt or equity securities and/or via development arrangements with industry partners.

We plan to reinvest a substantial portion of the net cash proceeds from the pending sale of the Louisiana portion of our Gulf of Mexico assets in longer-lived natural gas and oil assets onshore in North America. Our plans include structuring the reinvestment, where prudent, to optimize the tax effects under the tax free exchange rules of Section 1031 of the Internal Revenue Code. However, numerous market conditions and uncertainties may not allow for the reinvestment of all of the proceeds within the prescribed time period for the most tax efficient treatment and to the extent we are not able to timely reinvest any such proceeds, we would then be required to pay the resulting tax liability.

Stock Repurchase Program. In November 2005, our Board of Directors approved a plan for discretionary repurchases from time to time over 12 months ending in November 2006 of up to $200 million in company stock in conjunction with the divesture of all of our Gulf of Mexico assets. These purchases may be in the open market or in privately negotiated transactions, and will be subject to a number of considerations, including market conditions for our shares, applicable legal requirements and contractual restrictions, available cash, competing reinvestment opportunities in the acquisition market for oil and gas assets and other factors. We expect to retire any shares repurchased under this program. No repurchases were made during the first quarter of 2006.

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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 March 31, 2006, total debt was $424 million, of which approximately 41%, or $175 million, bears interest at a fixed interest rate of 7% per year. The remaining 59% of our total debt balance at March 31, 2006, or $249 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. Fluctuations in market interest rates will cause our annual interest costs to fluctuate. During the first three months of 2006, the interest rate on our outstanding bank debt averaged 6.26% per year. If the balance of our bank debt at March 31, 2006 were to remain constant, a 10% change in market interest rates would impact our cash flow by approximately $0.4 million per quarter.

Commodity 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, and our hedging policy prescribes that at the time we enter into a contract, all hedge structures meet the requirements for hedge accounting under SFAS 133, and that each transaction is specifically identified as a hedge for federal income tax purposes as defined in Section 1221(b)(2) of the Internal Revenue Code. While the use of certain hedging arrangements limits the downside risk of adverse price movements, it also limits increases in future revenues as a result of favorable price movements, as has been the case in recent years, especially during the last four months of 2005 and continuing into the first three months of 2006. 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 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*.)

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.

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 three-month periods from January 1 to March 31, 2006 and 2005, and provides the fair value at the end of each period.

	Three Months Ended March 31,	
	2006	**2005**
Change in Fair Value of Derivatives Instruments:	Before Tax (in thousands)	
Fair value of contracts at January 1	$ (417,658)	$ (75,149)
Realized loss on contracts settled during period	46,525	14,175
(Decrease) increase in fair value of all open contracts	221,683	(213,281)
Net change during period	268,208	(199,106)

Fair value of contracts outstanding at March 31	$ (149,450)	$ (274,255)

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Derivatives in Place as of the Date of Our Report

As of May 9, 2006, the following table summarizes, on a daily basis, our natural gas hedges in place for the remaining months of 2006 and for 2007 and 2008.

Concurrent with the pending sale of our Louisiana Gulf of Mexico assets, and after taking into account the divestiture and any acquisitions that appear imminent at the time of the divestiture, we estimate that we will liquidate approximately 80,000 MMBtu per day of our 2006 hedge position prior to closing of the transaction expected to occur on May 31, 2006. Depending on prices in effect at the time of liquidation, we estimate, based on prices in effect at May 9, 2006, the cost to unwind and settle the contracts could be between $20 million and $25 million.

Year	Transaction Type	Daily Volume (MMBtu/day)	NYMEX Price ($/MMBtu)	Floor Price ($/MMBtu)	Ceiling Price ($/MMBtu)
2006	Swap	20,000	$ 5.87		
2006	Swap	10,000	5.94		
	Total swaps	30,000			
2006	Costless collar	10,000		$5.50	$ 7.20
2006	Costless collar	10,000		5.50	7.25
2006	Costless collar	40,000		5.50	7.26
2006	Costless collar	20,000		5.75	7.20
2006	Costless collar	30,000		5.80	7.00
2006	Costless collar	50,000		5.82	7.00
2006	Costless collar	30,000		6.00	7.00
2006	Costless collar	20,000		6.00	7.02
2006	Costless collar	10,000		6.00	7.05
	Total collars	220,000			
Total daily volume 2006		250,000			
2007	Costless collar	20,000		$5.00	$ 6.50
2007	Costless collar	10,000		5.00	6.79
Total daily volume 2007		30,000			
2008	Costless collar	20,000		$5.00	$ 5.72
Total daily volume 2008		20,000			

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. For option contracts, we have the option, but not the obligation, to buy contracts at the strike price up to the day before the last trading day for that NYMEX contract.

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.

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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 March 31, 2006, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Part II. Other Information

Item 1A. Risk Factors

As of May 9, 2006, except as noted below, 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. The previously disclosed risk factors under the captions set forth below are supplemented as follows:

Our ability to sell assets and replace revenues generated from any sale of our Gulf of Mexico properties depends upon market conditions and numerous uncertainties.

We believe that the risk of successfully completing the sale of our Gulf of Mexico assets has been reduced subsequent to closing the sale of the Texas portion of the offshore assets on March 31, 2006 and the pending sale of substantially all of the Louisiana portion of the offshore assets scheduled to close, subject to customary closing conditions, on May 31, 2006. However, because our offshore assets accounted for 40% of our 2005 production and represented approximately 245 Bcfe, or 28% of our proved reserves, at December 31, 2005, our operating revenues and cash flows are expected to decrease following the sale of these offshore assets. There can be no assurance that we will be able to replace this sold production via the acquisition of new properties on attractive terms, with tax-efficient results, or at all, as market conditions, the availability of suitable properties, inherent acquisition risks and other uncertainties may impact our reinvestment of proceeds. If we are unable to identify acquisitions that we believe warrant our investment, then we intend to explore other options for allocating our capital.

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 March 31, 2006, an unrealized loss of $97.4 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. With the exception of (i) that portion of our contracts relating to Texas Gulf of Mexico production for which all previously deferred losses were completely reclassified from accumulated other comprehensive income to earnings in the first quarter of 2006 and (ii) all amounts relating to Louisiana Gulf of Mexico production that will be reclassified upon the sale of the Louisiana Gulf of Mexico assets expected to occur during the second quarter of 2006, all remaining deferred losses will be reclassed 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 $77.7 million, net of tax, with $19.7 million to be recognized thereafter. However, these amounts could vary materially as a result of changes in market conditions.

Item 4. Submission of Matters to a Vote of Security Holders

On April 28, 2006, we held our Annual Meeting of Stockholders. As of March 9, 2006, the record date for our Annual Meeting, there were 29,071,130 shares issues and outstanding and entitled to vote at this meeting. All matters brought for a vote before the shareholders as listed in our proxy statement were approved as follows:

1. The election of the following eight Directors of our company to serve until our next annual meeting:

Director	Votes For	Votes Withheld
Robert B. Catell	14,992,187	12,896,447
John U. Clarke	18,674,360	9,214,274
David G. Elkins	19,621,805	8,266,829
William G. Hargett	18,729,676	9,158,958
Harold R. Logan, Jr.	19,245,382	8,643,252
Thomas A. McKeever	19,302,906	8,585,728
Stephen W. McKessy	19,621,330	8,267,304
Donald C. Vaughn	19,181,813	8,706,821

As reflected in our March 17, 2006 proxy statement, Robert B. Catell currently serves as a director of three other publicly traded entities, including KeySpan Corporation, where he is chief executive officer. Based on public statements by certain of these other companies, we anticipate that the factors impacting Mr. Catell s voting results will be resolved in the near term.

2. The ratification and approval of Deloitte & Touche LLP as our independent public accountants for the fiscal year ending December 31, 2006:

Votes For	Votes Against	Abstained
27,493,302	9,967	385,365

Item 6. Exhibits

EXHIBITS	DESCRIPTION
10.1(1)	Purchase and sale agreement dated February 28, 2006 between The Houston Exploration Company, as seller, and Merit Management Partners I, L.P., Merit Management Partners II, L.P., Merit Management Partners III, L.P., Merit Energy Partners III, L.P., Merit Energy Partners D-III, L.P., Merit Energy Partners E-III, L.P. and Merit Energy Partners F-III, L.P., collectively, as buyer.
10.2(2)	Employment Agreement dated January 18, 2006 between Robert T. Ray and The Houston Exploration Company (Exhibit 99.1 to Current Report on Form 8-K dated January 18, 2006 (File No. 001-11899) and incorporated by reference).
10.3(2)	Employment Agreement dated March 27, 2006 between Carolyn M. Campbell and The Houston Exploration Company (Exhibit 99.1 to Current Report on Form 8-K dated March 27, 2006 (File No. 001-11899) and incorporated by reference).
12.1(1)	Computation of ratio of earnings to fixed charges.
31.1(1)	Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2(1)	Certification of Robert T. Ray, Chief Financial Officer, as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1(1)	Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2(1)	

Certification of Robert T. Ray, Chief Financial Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(1) Filed herewith.

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

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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: May 9, 2006	By: /s/ William G. Hargett William G. Hargett Chairman, President and Chief Executive Officer
Date: May 9, 2006	By: /s/ Robert T. Ray Robert T. Ray Senior Vice President and Chief Financial Officer
Date: May 9, 2006	By: /s/ James F. Westmoreland James F. Westmoreland Vice President and Chief Accounting Officer

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Index to Exhibits

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(1) Filed herewith.

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