HOUSTON EXPLORATION CO
Form 10-Q
May 04, 2005

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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, 2005
OR
o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from __________ to __________.

Commission File No. 001-11899

THE HOUSTON EXPLORATION COMPANY

(Exact name of registrant as specified in its charter)

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

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

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

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

As of May 4, 2005, 28,665,620 shares of Common Stock, par value $0.01 per share, were outstanding.

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Forward-Looking Statements and Other Information

All of the estimates and assumptions contained in this Quarterly Report on Form 10-Q (Quarterly Report) constitute forward-looking statements as that term is defined in 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 statements use forward-looking words such as anticipate, believe, continue, expect, estimate, intend, may, potential, predict, project, should, target, goal, objective or other similar expressions and discuss forward-l information. Forward-looking statements include all statements under the caption Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations involving the discussion of the following:

§ business strategy;

§ natural gas and oil reserves;

§ future production;

§ expected realized natural gas and oil prices;

§ expected costs and expenses;

§ anticipated capital expenditures;

§ future operating results;

§ future cash flows and borrowings;

§ pursuit of potential future acquisition opportunities;

§ identified drilling locations; and

§ sources of funding and the timing of exploration and development activities.

Although we believe that these forward-looking statements are based on reasonable assumptions, our expectations may not occur, and we cannot guarantee that the anticipated future results will be achieved. A number of factors could cause our actual future results to differ materially from those anticipated or implied in the forward-looking statements. These factors include, among other things:

§ the volatility of natural gas and oil prices;

§ the requirement to take writedowns if natural gas and oil prices decline or if our finding and development costs continue to increase;

§ the relatively short production lives of our reserves;

§ our ability to find, replace, develop and acquire natural gas and oil reserves;

§ the maturity of North American gas basins;

§ acquisition and investment risks;

§ our ability to meet our substantial capital requirements;

§ our outstanding indebtedness;

§ the uncertainty of estimates of natural gas and oil reserves and production rates;

§ the inherent hazards and risks involved in our operations;

§ dependence upon operations concentrated in three primary areas;

§ drilling risks;

§ our hedging activities;

§ compliance with environmental and other governmental regulations;

§ the competitive nature of our industry;

§ weather risks and other natural disasters; and

§ our customers ability to meet their obligations.

For additional discussion of these and other risks, uncertainties and assumptions, see Items 1 and 2. Business and Properties and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations contained in our Annual Report on Form 10-K for the year ended December 31, 2004. We undertake no obligation to publicly update or revise any forward-looking statements.

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, through May 31, 2004, our former subsidiary Seneca-Upshur Petroleum, Inc., and subsequent to October 8, 2004, THEC, LLC and THEC, LP on a consolidated basis.

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, 2004. 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. Consolidated Financial Statements

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

	March 31, 2005	December 31, 2004
Assets:		
Cash and cash equivalents	$ 13,760	$ 18,577
Accounts receivable	95,298	103,069
Inventories	1,357	976
Deferred tax asset	68,623	24,101
Prepayments and other	7,724	9,107
Total current assets	186,762	155,830
Natural gas and oil properties, full cost method		
Unevaluated properties	148,421	122,691
Properties subject to amortization	2,899,779	2,777,097
Other property and equipment	12,053	11,740
	3,060,253	2,911,528
Less: Accumulated depreciation, depletion and amortization	1,433,875	1,363,272
	1,626,378	1,548,256
Other non-current assets	17,360	18,491
Total Assets	$ 1,830,500	$ 1,722,577
Liabilities:		
Accounts payable and accrued expenses	$ 131,972	$ 118,971
Derivative financial instruments	193,849	68,081
Asset retirement obligation	2,141	662
Total current liabilities	327,962	187,714
Long-term debt and notes	340,000	355,000
Derivative financial instruments	80,406	7,068
Deferred income taxes	278,182	288,069
Asset retirement obligation	93,177	91,084

Other non-current liabilities	11,568	10,722
Total Liabilities	1,131,295	939,657
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, 50,000,000 shares authorized and 28,665,620 and 28,380,207 shares issued and outstanding at March 31, 2005 and December 31, 2004, respectively	287	284
Additional paid-in capital	285,057	273,002
Unearned compensation	(4,046)	(2,537)
Retained earnings	591,636	558,198
Accumulated other comprehensive (loss)	(173,729)	(46,027)
Total Stockholders Equity	699,205	782,920
Total Liabilities and Stockholders Equity	$ 1,830,500	$ 1,722,577

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, 2005	Three Months Ended March 31, 2004
Revenues:		
Natural gas and oil revenues	$ 165,490	$ 151,634
Other	230	248
Total revenues	165,720	151,882
Operating expenses:		
Lease operating	15,368	12,706
Severance tax	2,934	3,057
Transportation expense	2,766	2,736
Asset retirement accretion expense	1,325	1,288
Depreciation, depletion and amortization	70,603	60,964
General and administrative, net of amounts capitalized	11,123	6,088
Total operating expenses	104,119	86,839
Income from operations	61,601	65,043
Other (income) expense	1,454	110
Interest expense, net of amounts capitalized	3,434	2,287
Income before income taxes	56,713	62,646
Provision for taxes	23,275	22,956
Net income	$ 33,438	$ 39,690
Earnings per share:		
Net income per share basic	$ 1.17	$ 1.26
Net income per share diluted	$ 1.16	$ 1.25
Weighted average shares outstanding basic	28,499	31,598
Weighted average shares outstanding diluted	28,871	31,714

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,	
	2005	**2004**
Operating Activities:		
Net income	$ 33,438	$ 39,690
Adjustments to reconcile net income to net cash provided by operating activities:		
Deferred income tax expense	15,571	13,282
Depreciation, depletion and amortization	70,603	60,964
Asset retirement accretion expense	1,325	1,288
Stock compensation expense	1,012	517
Tax benefit non-qualified stock options	1,724	1,532
Unrealized loss due to ineffectiveness of derivative instruments	1,424	1,000
Amortization of premiums paid on derivative contracts		2,730
Changes in operating assets and liabilities:		
(Increase) decrease in accounts receivable	7,771	(6,925)
(Increase) decrease in inventories	(381)	(93)
(Increase) decrease in prepayments and other	1,383	612
(Increase) decrease in other assets	1,131	(2,970)
Increase (decrease) in deferred liabilities	846	6,727
Increase (decrease) in accounts payable and accrued expenses	13,001	12,805
Decrease in ARO liability for assets abandoned		(2,553)
Net cash provided by operating activities	148,848	128,606
Investing Activities:		
Investment in property and equipment	(146,627)	(85,222)
Dispositions	150	13,138
Net cash used in investing activities	(146,477)	(72,084)
Financing Activities:		
Proceeds from long-term borrowings	85,000	20,000
Repayments of long-term borrowings	(100,000)	(77,000)
Proceeds from issuance of common stock from exercise of stock options	7,812	11,629
Net cash used in financing activities	(7,188)	(45,371)
(Decrease) increase in cash and cash equivalents	(4,817)	11,151
Cash and cash equivalents, beginning of year	18,577	2,569
Cash and cash equivalents, end of year	$ 13,760	$ 13,720

Supplemental Information:				
Cash paid during period for:				
Interest	$	2,107	$	876
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. Our core areas of operations are South Texas, offshore in the shallow waters of the Gulf of Mexico, the Arkoma Basin of Oklahoma and Arkansas and the Rocky Mountain region where, during 2003, we began operations with an initial focus in the Uinta Basin of northeastern Utah and during 2004, we expanded our focus to the DJ Basin in Eastern Colorado.

We were founded in December 1985 as a Delaware corporation and began exploring for natural gas and oil on behalf of KeySpan Corporation, our then parent company. KeySpan, a member of the Standard & Poor s 500 Index, is a diversified energy provider whose principal natural gas distribution and electric generation operations are located in the Northeastern United States. In September 1996, we completed our initial public offering and sold approximately 31% of our shares to the public. Through a series of three separate transactions, the first in February 2003 and the last in November 2004, KeySpan completely divested of its interest in the common stock of our company.

Principles of Consolidation

Our consolidated financial statements for the period ended March 31, 2005, include our accounts and the accounts of our wholly-owned subsidiaries. All significant inter-company balances and transactions have been eliminated.

Our consolidated financial statements for the period ended March 31, 2004, include our accounts and the accounts of Seneca-Upshur Petroleum, Inc., which was our wholly-owned subsidiary until June 2, 2004, when we conveyed all of the shares of Seneca-Upshur to KeySpan in connection with an asset exchange transaction. Seneca-Upshur was previously our only subsidiary. Seneca-Upshur is a natural gas exploration and production company located in West Virginia. All significant inter-company balances and transactions were eliminated.

Interim Financial Statements

Our balance sheet at March 31, 2005, 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 Securities and Exchange Commission (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, 2004, is derived from our December 31, 2004 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, 2004.

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 and the reported amounts of revenues and expenses during the reporting periods. Our most significant financial 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)

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 engages in activities from which it may earn revenues and incur expenses. Separate financial information is available, and this information is 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, 2005, we had production imbalances representing assets of $4.1 million and liabilities of $4.4 million. At December 31, 2004, we had production imbalances representing assets of $3.3 million and liabilities of $4.0 million. The primary sources of our production imbalances relate to Eugene Island 331, acquired in October 2003 from Transworld Exploration and Production Inc., and to various Arkoma wells. Production imbalances are included in the line items other non-current assets and other non-current liabilities on the balance sheet.

Net Income Per Share

Basic earnings per share is calculated by dividing net income by the weighted average number of shares of common stock outstanding during the period. No dilution for any potentially dilutive securities is included. Fully diluted earnings per share assumes the conversion of all potentially dilutive securities and is calculated by dividing net income by the sum of the weighted average number of shares of common stock outstanding plus all potentially dilutive securities.

	Three Months Ended March 31,	
	2005	**2004**

	(in thousands)	
Numerator:		
Net income	$ 33,438	$ 39,690
Denominator:		
Weighted average shares outstanding	28,499	31,598
Add dilutive securities: Stock options	372	116
Total weighted average shares outstanding and dilutive securities	28,871	31,714
Earnings per share basic:	$ 1.17	$ 1.26
Earnings per share diluted:	$ 1.16	$ 1.25

For the three months ended March 31, 2005 and 2004, the calculation of shares outstanding for diluted earnings per share does not include the effect of outstanding stock options to purchase 377,725 and 1,585,960 shares, respectively, because the

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

exercise price of these shares was greater than the average market price for the year, which would have an antidulitive effect on earnings 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, 2005 and 2004.

	Three Months Ended March 31, 2005	Three Months Ended March 31, 2004
	(in thousands)	
Net income	$ 33,438	$ 39,690
Other comprehensive income (loss)		
Derivative instruments settled and reclassified, net of tax	9,157	7,461
Change in unrealized (loss) fair value of open contracts, net of tax	(136,859)	(36,216)
Total other comprehensive (loss)	(127,702)	(28,109)
Comprehensive income (loss)	$ (94,264)	$ 11,581

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,

§ 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, 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 adjusted for basis or location differential, held constant over the life of the reserves. We use derivative financial instruments that qualify for cash flow hedge accounting under SFAS 133, Accounting for Derivative Instruments and Hedging Activities, to hedge against the volatility of natural gas prices, and in accordance with SEC guidelines, we include estimated future cash flows from our hedging program in our ceiling test calculation. In addition, subsequent to the adoption of SFAS 143, Accounting for Asset Retirement Obligations, the future cash outflows associated with settling asset retirement obligations are excluded from the computation of the discounted present value of future net revenues for the purposes of the ceiling test calculation.

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THE HOUSTON EXPLORATION COMPANY
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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, seismic data, 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 included in our unevaluated property balance are assessed on a quarterly basis for possible impairment or reduction in value. We estimate that these costs will be evaluated within a four-year period.

Asset Retirement Obligations

For us, asset retirement obligations (ARO) represent the future abandonment costs of tangible assets such as platforms, wells, service assets, pipelines, and other facilities. SFAS 143, Accounting for Asset Retirement Obligations, requires that the fair value of a liability for an asset s retirement obligation be recorded in the period in which it is incurred if a reasonable estimate of fair value can be made, and that the corresponding cost is capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, an adjustment is made 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. We carry ARO assets on the balance sheet as part of our full cost pool, and include these ARO assets in our amortization base for the purposes of calculating depreciation, depletion and amortization expense. For the purposes of calculating the ceiling test, the future cash outflows associated with settling the ARO liability are excluded from the computation of the discounted present value of estimated future net revenues.

The following table describes changes in our ARO liability during the three-month periods ended March 31, 2005 and 2004. The ARO liability in the table below includes amounts classified as both current and long-term at period end.

	Three Months Ended March 31,	
	2005	2004
	(in thousands)	
ARO liability at January 1	$ 91,746	$ 92,357
Accretion expense	1,325	1,288
Liabilities incurred from drilling	1,449	1,812
Liabilities settled assets sold		(2,928)
Liabilities settled assets abandoned		(3,957)
Changes in estimates	798	
ARO liability at March 31	$ 95,318	$ 88,572

Derivative Instruments and Hedging Activities

Our hedging policy does not permit us to hold derivative instruments for trading purposes. In our hedging program, we utilize a variety of derivative instruments, including swaps, collars and options. We generally place contracts with major financial institutions and other credit-worthy counterparties. Although our hedging program protects 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. 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 protect our cash flows if the price differential increases between the NYMEX price and index price for the point of sale.

Our derivative instruments are designated cash flow hedges and qualify for hedge accounting under SFAS 133, Accounting for Derivative Instruments and Hedging Activities, as amended, and, accordingly, we carry the fair market value of our derivative instruments on the balance sheet as either an asset or liability and defer unrealized gains or losses 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 the hedged production occurs. If any

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

ineffectiveness occurs, amounts are recorded directly to the income statement. During the three-month periods ended March 31, 2005 and 2004, our net income includes an unrealized loss of $1.4 million ($0.9 million net of tax) and $1.0 million ($0.7 million net of tax), respectively, which represents the ineffective portion of our open derivative contracts that were not eligible for deferral. The ineffectiveness was primarily a result of changes at the end of the current period in the price differentials between the index price of the derivative contract, which uses a NYMEX index, and index price for the point of sale for the cash flow that is being hedged, the majority of which is the Houston Ship Channel index.

Based on market prices at March 31, 2005, we recorded an unrealized loss in accumulated other comprehensive income of $173.7 million, net of tax, representing the fair value of our open contracts. Any loss will be realized in future earnings at the time of the related sales of natural gas production applicable to specific hedges. If prices in effect at March 31, 2005, were to remain unchanged, over the next 12-month period, we would expect to reclassify from accumulated other comprehensive income to earnings a loss of $122.4 million, net of tax, relating to our open derivative contracts. However, these amounts could vary materially as a result of changes in market conditions.

From time to time, if the fair value of an open contract or contracts exceeds our available credit limit with a particular counterparty, we could be required to post a letter of credit to further guarantee our performance. As of March 31, 2005, we did not have any outstanding letters of credit issued relating to derivative contracts.

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. As a result, we recorded as compensation expense the fair value of all stock options issued subsequent to January 1, 2003. No expense for stock options has been recorded for grants made in years prior to January 1, 2003. Prior to 2003, 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. Accordingly, compensation cost for stock options was measured as the excess, if any, of the fair value of common stock at the date of the grant over the amount the employee must pay to acquire the common stock. If the exercise price of a stock option was equal to the fair market value at the time of grant, no compensation expense was incurred. If we had accounted for all stock options using the fair value method as recommended in SFAS 123, 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 and 2004.

	Three Months Ended March 31,	
	2005	**2004**
	(in thousands)	
Net income as reported	$ 33,438	$ 39,690
Add: Stock-based compensation expense included in net income, net of tax	446	230
Less: Stock-based compensation expense determined using fair value method, net of tax	(802)	(1,267)
Net income pro forma	$ 33,082	$ 38,653

Net income per share basic as reported	$	1.17	$	1.26
Net income per share diluted as reported		1.16		1.25
Net income per share basic pro forma	$	1.16	$	1.22
Net income per share diluted pro forma		1.15		1.22

The effects of applying SFAS 123 in this pro forma disclosure may not be representative of future amounts. The weighted average fair value of options at their grant date for the first three months of 2005 and 2004 were $21.89 and $12.20, respectively. The fair value of each option grant was estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions used for grants during the three months ended March 31, 2005 and 2004:

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

	Three Months Ended March 31,	
	2005	**2004**
Risk-free interest rate	3.97%	4.21%
Expected years until exercise	5	5
Expected stock volatility	35.60%	37.08%
Expected dividends		

For the risk-free interest rate, we utilize daily rates for five-year United States treasury bills with constant maturity. The expected life is based on historical exercise activity over the previous nine-year period. The expected volatility is based on historical volatility and measured using the average closing price of our stock over a 60-month period. We believe historical volatility is the most accurate measure of future volatility of our common stock.

The following table provides the detail of stock compensation expenses incurred during each of the three-month periods ended March 31, 2005 and 2004.

	Three Months Ended March 31,	
	2005	**2004**
	(in thousands)	
Options	$ 817	$ 455
Restricted stock	195	62
Stock compensation expense, gross	1,012	517
Amounts capitalized	(322)	(163)
Stock compensation expense, net	$ 690	$ 354

Recent Accounting Pronouncements

On December 16, 2004, the FASB revised Statement 123 (revised 2004), Share-Based Payment that will require compensation costs related to share-based payment transactions (e.g., issuance of stock options and restricted stock) to be recognized in the financial statements. With limited exceptions, the amount of compensation cost will be measured based on the grant date fair value of the equity or liability instruments issued. In addition, liability awards will be remeasured each reporting period. Compensation cost will be recognized over the period that an employee provides service in exchange for the award. Statement 123(R) replaces SFAS 123, Accounting for Stock-Based Compensation, and supersedes Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees. For us, SFAS 123(R), as amended by SEC Release 34-51558, is effective for our first fiscal year beginning after June 15, 2005, or January 1, 2006. Entities that use the fair-value-based method for either recognition or disclosure under SFAS 123 are required to apply SFAS 123(R) using a modified version of prospective application. Under this method, an entity records compensation expense for all awards it grants after the date of adoption. In addition, the entity is required to record compensation expense for the unvested portion of previously granted awards that remain outstanding at the date of adoption. In addition, entities may elect to adopt SFAS 123 (R) using a modified retrospective method whereby previously issued financial statements are restated based on the expense previously calculated and reported in their pro forma footnote disclosures.

On January 1, 2003, we adopted the fair value expense recognition provisions of SFAS 123 as amended by SFAS 148, Accounting for Stock-Based Compensation Transition and Disclosure using the prospective method as defined by the SFAS 148. As a result, we have recognized compensation expense for all stock options granted subsequent to January 1, 2003, with no expense recognized for grants made prior to 2003. Adoption of SFAS 123(R) will require us to recognize compensation expense over the remaining service period for the unvested portion of all options granted during 2000, 2001 and 2002. All options granted prior to 2000 are fully vested. We expect to adopt SFAS 123(R) on January 1, 2006, using the modified version of the prospective application. We are currently evaluating the effect adopting SFAS 123(R) will have to our financial statements.

On March 29, 2005, the SEC released Staff Accounting Bulletin (SAB) 107 providing additional guidance in applying the provisions of SFAS 123(R), Share-Based Payment. SAB 107 should be applied when adopting SFAS 123(R) and

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addresses a wide range of issues, focusing on valuation methodologies and the selection of assumptions. In addition, SAB 107 addresses the interaction of SFAS 123(R) with existing SEC guidance.

NOTE 2 Long-Term Debt and Notes

	March 31, 2005	December 31, 2004
	(in thousands)	
Senior Debt:		
Revolving bank credit facility, due April 1, 2008	$ 165,000	$ 180,000
Subordinated Debt:		
7% senior subordinated notes, due June 15, 2013	175,000	175,000
Total long-term debt and notes	$ 340,000	$ 355,000

The carrying amount of borrowings outstanding under the revolving bank credit facility approximates fair value as the interest rates are tied to current market rates. At March 31, 2005, the quoted market value of our $175 million of 7% senior subordinated notes was 99% of the $175 million carrying value, or $173 million. At December 31, 2004, the quoted market value of our $175 million of 7% senior subordinated notes was 101% of the $175 million carrying value, or $177 million.

Revolving Bank Credit Facility

We maintain a revolving bank 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 Fleet National Bank as co-syndication agents and BNP Paribas and Comerica Bank as co-documentation agents. The facility provides us with a commitment of $400 million, which may be increased at our request and with prior approval from Wachovia to a maximum of $450 million. Amounts available for borrowing under the credit facility are limited to a borrowing base. Our borrowing base is $400 million, which is expected to remain in effect until the next scheduled redetermination on October 1, 2005. Up to $40 million of the borrowing base is available for the issuance of letters of credit. Outstanding borrowings are unsecured and rank senior in right of payment to our $175 million 7% subordinated notes. The facility matures on April 1, 2008. At March 31, 2005, we had $165 million in outstanding borrowings under the credit facility and $0.4 million in outstanding letter of credit obligations.

Interest is payable on borrowings under our revolving bank 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 1.25% and 2.00%, 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 bank credit facility contains customary negative covenants that place restrictions and limits on, among other things, the incurrence of debt, guarantees, liens, leases and certain investments. Our subsidiaries are guarantors under the credit facility, and we are restricted and limited in our ability to pay cash dividends, to purchase or redeem our stock and to 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.

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At March 31, 2005, and December 31, 2004, 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 bank credit facility, and will rank senior or equal in right of payment to all existing and future subordinated indebtedness.

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

§ incurrence of additional indebtedness and issuance of preferred stock;

§ repayment of certain other indebtedness;

§ payment of dividends or certain other distributions;

§ investments and repurchases of equity;

§ use of the 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; or

§ 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.

NOTE 3 Stockholders Equity

Increase in Number of Shares Outstanding

At our annual meeting of stockholders on April 26, 2005, our Board of Directors received shareholder approval to increase the number of shares we are authorized to issue to up to 105,000,000 shares of stock, including up to 100,000,000 shares of common stock and up to 5,000,000 shares of preferred stock. An amendment to our Restated Certificate of Incorporation was filed with the Secretary of State of the State of Delaware on April 26, 2005 to reflect the increase.

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, will not 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 (telephones, copiers and faxes). The terms of these agreements have various expiration dates from 2005 through 2009. Future minimum lease payments for the remainder of 2005 and

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each of the subsequent four years from 2006 through 2009 are $1.2 million, $1.5 million, $1.6 million, $1.6 million and $0.9 million, respectively.

Purchase Obligations

We have committed to acquire additional offshore seismic data under an existing license agreement for up to $7.7 million which is payable in January 2006.

Letters of Credit

We had $0.4 million of letters of credit outstanding at March 31, 2005, and December 31, 2004. These letters of credit were issued for natural gas and oil operating activities, none of which were collateralized.

Drilling Contract

In February 2005, we entered into a one-year contract for the use of a drilling rig in the Uinta Basin. Under the terms of the contract, we are obligated for up to an estimated $3.4 million in fees for use of the rig during the one-year term.

NOTE 5 Related Party Transactions

Employment Agreements

On February 10, 2005, we entered into an employment agreement with Joanne C. Hresko, our Vice President and General Manager-Onshore Division. On March 10, 2005, we entered into an employment agreement with John E. Bergeron, Jr., our new Vice President and General Manager Offshore Division. On April 13, 2005, we entered into an employment agreement with Jeffrey B. Sherrick, our new Senior Vice President of Corporate Development.

On February 8, 2005, we entered into amended and restated employment agreements with William G. Hargett, our President and Chief Executive Officer, Steven L. Mueller, our Executive Vice President and Chief Operating Officer, John H. Karnes, our Senior Vice President and Chief Financial Officer, James F. Westmoreland, our Vice President and Chief Accounting Officer, and Roger B. Rice, our Senior Vice President-Administration. Each agreement is for a term of three years, with automatic one-year extensions thereafter unless we or the executive provide notice of termination at least 90 days prior to the end of the applicable term.

By entering into the amended and restated employment agreements and terminating their prior employment agreements with us, Messrs. Hargett, Mueller, Karnes, Westmoreland and Rice gave up certain rights, including the right to receive severance for a termination of employment following a change of control of our company absent the existence of good reason and the right to guaranteed annual stock option grants and incentive compensation bonuses (which will now be subject to the discretion of our Compensation and Management Development Committee. In addition to these rights, Mr. Hargett gave up the right to receive a transaction bonus upon the occurrence of certain corporate transactions involving our company, and all of the executives have agreed to broader non-competition provisions under the amended and restated agreements.

In consideration of their entering into the amended and restated agreements and foregoing such rights, we paid to each of these executives during the first quarter of 2005 cash and/or restricted stock as follows: for Mr. Hargett, $4,220,043 in cash; for Mr. Mueller, $353,866 in cash and 6,553 shares of restricted stock; for Mr. Karnes, 12,892 shares of restricted stock; for Mr. Westmoreland, $291,300 in cash and 5,394 shares of restricted stock; and for Mr. Rice, $284,349 in cash and 5,266 shares of restricted stock. The restricted stock will vest over a period of five years in accordance with the terms of our 2004 Long-Term Incentive Compensation Plan.

All of the employment agreements provide that if we terminate an executive s agreement without cause (as defined in the employment 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 of our company), 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 welfare benefits. The agreements further provide that if any payments made to the executives, whether or not under the agreement, would result in an excise tax being imposed on the executives under Section 4999 of the Internal Revenue Code, we will make each of the executives whole on a net after-tax basis.

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We may terminate any employment agreement for cause or upon the death or disability of the executive without financial obligation (other than payment of any accrued obligations). Each executive may terminate his or her employment agreement at any time 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 automatically will vest and any other conditions to such awards shall be deemed satisfied.

Termination of Employment Agreements

On February 17, 2005, Timothy R. Lindsey, Senior Vice President of Exploration, and Tracy Price, Senior Vice President Land, resigned from the company, effective March 1, 2005. Their resignations were prompted by an organizational change made in November 2004, in which they were given new reporting responsibilities. Upon resignation, their employment agreements were terminated and each received a lump-sum severance payment in the amount of 2.99 times his total compensation, the continuation of certain health and medical benefits for a period of at least 12 months and accelerated vesting of all outstanding stock options and restricted stock. During the fourth quarter of 2004, we recognized additional general and administrative expense of $3.1 million relating to the entitlements under these employment agreements.

NOTE 6 Acquisitions

East Texas Acquisitions

On March 15, 2005, we completed the purchase of certain natural gas and oil producing properties and associated gathering pipelines and equipment, together with developed and undeveloped acreage, located in the Rusk County, Texas, from Dale Gas Partners, L.P. The $22.0 million purchase price was paid in cash and financed by borrowings under our revolving bank credit facility. The properties purchased cover approximately 5,776 gross acres located in South Oak Hill Field, which is in close proximity to our existing operations in the Willow Springs Field, and represents interests in three producing wells and one well in the completion stage. We operate all of the wells acquired and our working interest is 100%. Total proved reserves associated with the interests acquired were 9.1 Bcfe as of March 15, 2005, the effective date of the transaction. In addition, we entered into a letter agreement with Dale Resources East Texas L.L.C. to acquire a second group of seven producing wells together with undeveloped acreage in the adjacent North Blocker Field, located in Harrison County, Texas. The letter agreement covers the acquisition of a 50% working interest in the seven wells, all of which will be operated by us, and 4,679 gross acres, for a purchase price of $9.2 million. Total proved reserves associated with the interests to be acquired are estimated at 7.7 Bcfe, as of April 1, 2005, the effective date of the transaction.

NOTE 7 Subsequent Events

East Texas North Blocker Field Acquisition

On April 5, 2005, we completed the acquisition of a 50% working interest in seven producing wells together with undeveloped acreage located in the North Blocker Field located in Harrison County, Texas from Dale Resources East Texas L.L.C. as described above in Note 6 Acquisitions. The $9.2 million purchase price was paid in cash and financed with borrowings under our revolving bank credit facility.

Letters of Credit Issued for Hedging Activities

Subsequent to the balance sheet date and as a result of increases in the market price of natural gas, the fair value of our open derivative contracts increased beyond our available credit limit with one counterparty. As a result, in April 2005, we were required to issue letters of credit totaling $3.3 million to further guarantee our performance on open derivative contracts.

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

The following discussion is intended to assist you in understanding our business and the 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 for the year ended December 31, 2004.

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 Risk Factors Affecting Our Business beginning on page 15 of our Annual Report on Form 10-K for additional discussion of some of these factors and risks.

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. Our core areas of operations are South Texas, offshore in the shallow waters of the Gulf of Mexico and the Arkoma Basin of Oklahoma and Arkansas. During 2003, we initiated operations in the Rocky Mountain Region, with an initial focus in the Uinta Basin of northeastern Utah, and during 2004, we expanded our focus to include the DJ Basin of Eastern Colorado. We operate as one segment as each of our operating areas has similar economic characteristics and each meets the criteria for aggregation as defined in the Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) 131, Disclosures about Segments of an Enterprise and Related Information.

At December 31, 2004, net proved reserves were 793 billion cubic feet equivalent, or Bcfe, with a standardized measure of future net cash flows including income taxes, discounted at 10% per annum, of $1.4 billion. Our reserves are fully engineered on an annual basis by independent petroleum engineers. Approximately 94% of our proved reserves at December 31, 2004, were natural gas, approximately 63% of which were classified as proved developed. As of December 31, 2004, we operated approximately 77% of our producing wells. Daily production averaged 339 million cubic feet of natural gas equivalent or MMcfe in 2004.

We were founded in December 1985 as a Delaware corporation and began exploring for natural gas and oil on behalf of KeySpan Corporation, our then parent company. KeySpan, a member of the Standard & Poor s 500 Index, is a diversified energy provider whose principal natural gas distribution and electric generation operations are located in the Northeastern United States. In September 1996 we completed our initial public offering and sold approximately 31% of our shares to the public. Through three separate transactions, the first in February 2003 and the last in November 2004, KeySpan completely divested of its investment in the common stock of our company.

Source of Our Revenues

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 utilize derivative instruments to hedge future sales prices on a significant portion of our natural gas production. During the first three months of both 2005 and 2004, the use of derivative instruments prevented us from realizing the full benefit of upward price movements and may continue to do so in future periods.

Principal Components of Our Cost Structure

- *Lease Operating Expenses.* The day-to-day costs incurred to bring hydrocarbons out of the ground and to the market together with the daily costs incurred to maintain our producing properties. These costs include: lease operating expense, severance tax and transportation expense, which costs are expected to increase.

- *Depreciation, Depletion and Amortization*. The systematic expensing of the capital costs incurred to acquire, explore and develop natural gas and oil. As a full cost company, we capitalize all costs associated with our acquisition, exploration and development efforts, including interest and certain general and administrative costs, and apportion these costs to each unit of production through depreciation, depletion and amortization expense. Generally, if reserve quantities are revised up or down, the depreciation, depletion and amortization rate per unit of production will change inversely.

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- § *Asset Retirement Accretion Expense.* The systematic, monthly accretion of the future abandonment costs of tangible assets such as platforms, wells, service assets, pipelines, and other facilities.

- § *General and Administrative Expense.* Overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, managing our production and development operations and legal compliance are included in our general and administrative expense. We capitalize general and administrative expense directly related to our acquisition, exploration and development activities.

- § *Interest.* We typically finance our working capital requirements and acquisitions with borrowings under our revolving bank credit facility, and longer term, with publicly traded debt instruments. As a result, we incur substantial interest expense that correlates to both fluctuations in interest rates and our acquisition activity. Acquisitions are a critical element of our growth strategy. We expect to continue to incur significant interest expense as we continue to grow. We capitalize interest directly related to our unevaluated properties that are not being amortized.

- § *Income Taxes.* We are subject to state and federal income taxes and are currently in a tax paying position. We expect to continue to recognize current tax expense as long as we are generating taxable income.

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.

Recent Accounting Pronouncements

On December 16, 2004, the FASB revised Statement 123 (revised 2004), Share-Based Payment that will require compensation costs related to share-based payment transactions (e.g., issuance of stock options and restricted stock) to be recognized in the financial statements. With limited exceptions, the amount of compensation cost will be measured based on the grant-date fair value of the equity or liability instruments issued. In addition, liability awards will be remeasured each reporting period. Compensation cost will be recognized over the period that an employee provides service in exchange for the award. Statement 123(R) replaces SFAS 123, Accounting for Stock-Based Compensation, and supersedes Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees. For us, SFAS 123(R), as amended by SEC Release 34-51558, is effective for our first fiscal year beginning after June 15, 2005, or January 1, 2006. Entities that use the fair-value-based method for either recognition or disclosure under SFAS 123 are required to apply SFAS 123(R) using a modified version of prospective application. Under this method, an entity records compensation expense for all awards it grants after the date of adoption. In addition, the entity is required to record compensation expense for the unvested portion of previously granted awards that remain outstanding at the date of adoption. In addition, entities may elect to adopt SFAS 123 (R) using a modified retrospective method where by previously issued financial statements are restated based on the expense previously calculated and reported in their pro forma footnote disclosures.

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addresses a wide range of issues, focusing on valuation methodologies and the selection of assumptions. In addition, SAB 107 addresses the interaction of SFAS 123(R) with existing SEC guidance.

Overview of Results for the First Quarter of 2005

The sustained strength of commodity prices throughout the first three months of 2005, nearly flat average daily production quarter-over-quarter and a 20% increase in operating expenses were the primary factors behind results for operations, earnings and cash flows during the first quarter of 2005. During the first three months of 2005:

§ We generated $33.4 million in net income, a decrease of 16% from first quarter 2004;

§ We produced approximately 30 Bcfe and our average daily production rate was 331 MMcfe per day during the first quarter of 2005 compared to 332 MMcfe per day during the first quarter of 2004, primarily as a result of shut-in production since the fourth quarter of 2004 at High Island 115 and the depletion of a well at High Island 47, two key producing properties during 2004;

§ We generated $148.8 million in net cash flows from operating activities and invested $146.3 million in natural gas and oil properties, which included $22.6 million for producing property acquisitions;

§ We drilled 80 wells, of which 60, or 75%, were successful with 25 successful wells in South Texas, 14 in Arkoma and 21 in the Rockies;

§ We expanded our East Texas acreage position in March 2005 through the acquisition of a 100% working interest in 5,776 gross acres and three producing wells for $22.0 million with proved reserves of approximately 9.1 Bcfe as of March 15, 2005, and on April 5, 2005 acquired a 50% working interest in an additional 4,679 acres and seven producing wells for $9.2 million with proved reserves of approximately 7.7 Bcfe as of April 1, 2005;

§ We successfully integrated the Gulf of Mexico producing properties acquired in September and October 2004 from BP Exploration & Production Inc. and Orca Energy, L.P., respectively;

§ We incurred $2.8 million in expense as a result of a payout settlement at East Cameron 82 whereby our working interest in the A3 well has subsequently been reduced from 50% to 35%;

§ We renegotiated employment agreements with five of our key executive officers, including our Chief Executive Officer, Chief Operating Officer and Chief Financial Officer, and incurred additional general and administrative expense of $5.0 million;

§ We decreased our outstanding borrowings under our revolving bank credit facility by a net $15 million; and

§ As a result of higher market prices for natural gas at March 31, 2005, the fair value of our open derivative contracts increased from a liability of $75.1 million ($48.5 million net of tax) at December 31, 2004, to a liability of $274.3 million ($177.2 million net of tax) at March 31, 2005.

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Operating and Financial Results for the Three Months Ended March 31, 2005 Compared to the Three Months Ended March 31, 2004

Summary Operating Information:	2005	2004	Variance	
	Three Months Ended March 31, (in thousands)			
Operating revenues	$ 165,720	$ 151,882	$ 13,838	9%
Operating expenses	104,119	86,839	17,280	20%
Income from operations	61,601	65,043	(3,442)	-5%
Net income	33,438	39,690	(6,252)	-16%
Production:				
Natural gas (MMcf)	27,357	28,132	(775)	-3%
Oil (MBbls)	406	348	58	17%
Total (MMcfe) [1]	29,793	30,220	(427)	-1%
Average daily production (MMcfe/d)	331	332	(1)	
Average Sales Prices:				
Natural Gas (per Mcf) realized [2]	$ 5.42	$ 4.99	$ 0.43	9%
Natural Gas (per Mcf) unhedged	5.99	5.43	0.56	10%
Oil (per Bbl) realized [2]	42.17	32.50	9.67	30%
Oil (per Bbl) unhedged	42.17	32.50	9.67	30%

(1) Mcfe is defined as one million 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 realized prices include the effect of hedges.

Income from Operations

Operating income for the first quarter of 2005 decreased by $3.4 million, or 5%, as compared to the first quarter of 2004, primarily as a result of a 20% increase in operating expenses. Operating revenues were 9% higher compared to the first quarter 2004 due to higher average realized prices for both natural gas and oil as production volumes remained approximately unchanged, declining by just 1%.

Production Volume

We experienced a 1% decrease in production volume for the first three months of 2005 as compared to the first three months of 2004, primarily as a result of a mechanical problem at High Island 115 and a depleted well at High Island 47. For the first three months of 2005, we added production from offshore properties acquired during September and October 2004 and experienced production growth in Arkoma and the Rockies from drilling.

Onshore. Daily production rates increased 1% from an average of 185 MMcfe per day during the first quarter of 2004 to 187 MMcfe per day during the first quarter of 2005. The Arkoma Basin and the Rockies were our onshore growth areas during the first quarter of 2005. In Arkoma, we added 10 MMcfe per day in newly developed production, increasing our average daily rate by 30% from 33 MMcfe per day during the first quarter of 2004 to 43 MMcfe per day during the first quarter of 2005. In the Rockies, we added 5 MMcfe per day from wells completed since the end of the first quarter of 2004. In South Texas, our average daily production declined by 6 MMcfe per day from 141 MMcfe per day during the first quarter of 2004 to 135 MMcfe per day during the first quarter of 2005. The decline in South Texas production was due in part to our curtailment of drilling operations during the fourth quarter of 2004. As a result of rising rig rates and service costs, we reduced our onshore drilling rig activity late in the fourth quarter of 2004 to keep capital spending within our 2004 budgeted levels.

Offshore. Daily production rates decreased by 2%, or 3 MMcfe per day, from an average of 147 MMcfe per day during the first quarter of 2004 to an average of 144 MMcfe per day during the first quarter of 2005. Declining rates from existing and maturing properties outpaced production added from our September and October 2004 acquisitions and from new wells placed on-line during the first quarter of 2005. According to our current drilling and workover schedule for 2005, we expect most of our offshore production growth to occur during the second half of 2005. Quarter-over-quarter, the decline in

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our average daily production rate was magnified by the depletion of a well at High Island 47 and a mechanical problem at High Island 115, which on a combined basis contributed approximately 20 MMcfe per day to our production during the first quarter of 2004. At High Island 47, a sidetrack of the No. 1 well is currently in the completion stage, and we expect initial production from the new well during May 2005. At High Island 115, a sidetrack of the No. 1 well is scheduled to begin drilling during the second quarter of 2005, with the goal of restoring production late in the third quarter of 2005.

Commodity Prices and Effects of Hedging

Our average unhedged or sales price for natural gas increased by 10% from $5.43 per Mcf during the first three months of 2004 to $5.99 per Mcf during the first three months of 2005. Included in natural gas revenues for the first three months of 2005 is a loss of $15.6 million from natural gas hedging activities, which is $3.1 million higher than our loss from hedging activities incurred in the first quarter of 2004. For the current quarter, the $15.6 million hedge loss includes an unrealized loss of $1.4 million representing the ineffective portion of our derivative instruments that are not eligible for deferral under SFAS 133. The ineffectiveness was a result of changes during the period in the price differentials between the index price of the derivative contract, which uses a New York Mercantile Exchange (NYMEX) index, and the index price for the point of sale for the cash flow that is being hedged, the majority of which is the Houston Ship Channel index. As a result of the loss from hedging activities, we realized an average natural gas price during the first quarter of 2005 of $5.42 per Mcf that was 90% of, or $0.57 per Mcf lower than our average sales price. During the first quarter of 2004, we incurred a hedge loss from natural gas derivatives of $12.5 million, which is included in natural gas revenues and includes an unrealized loss of $1.0 million recognized for ineffectiveness, resulting in an average realized price of $4.99 per Mcf that was 92% of, or $0.44 per Mcf lower than our average sales price during the first quarter of 2004.

Operating Expenses

	Three Months Ended March 31,			
Operating Expenses per Mcfe	**2005**	**2004**	**Variance**	
Lease operating expense	$ 0.52	$ 0.42	$ 0.10	24%
Severance tax	0.10	0.10		
Transportation expense	0.09	0.09		
Asset retirement accretion expense	0.04	0.04		
Depreciation, depletion and amortization	2.37	2.02	0.35	17%
General and administrative, net	0.37	0.20	0.17	85%
Total operating expenses per unit of production	$ 3.49	$ 2.87	$ 0.62	22%

Total operating expenses on an absolute dollar basis increased 20% during the first quarter of 2005 as compared to the first quarter of 2004 primarily as a result of higher lease operating expenses, higher depreciation, depletion and amortization expense and non-recurring general and administrative expenses. On a unit of production basis, operating expenses increased $0.62 per Mcfe produced, or 22%, for first quarter 2005 compared to first quarter 2004. Depreciation, depletion and amortization combined with asset retirement expense accounted for $0.35 of the increase, additional general and administrative expense as a result of payments made pursuant to the renegotiation of executive employment agreements contributed $0.17 per Mcfe and rising lease operating expenses added $0.10 to the total per unit increase.

Lease Operating Expense. On an absolute dollar basis, lease operating expense increased by 21% during the first quarter of 2005 as compared to the first quarter of 2004. This increase relates primarily to properties acquired, rising service costs and continued expansion of our operating base. During 2004 we successfully drilled and completed 177 new wells and acquired 12 new blocks in the central Gulf of Mexico pursuant to the September and October Gulf of Mexico acquisitions. We remain committed to minimizing our operating cost structure; however, we expect to experience higher lease operating expense throughout the remainder of 2005 as service costs are increasing and as we plan to continue our acquisition activities.

Severance Tax. Severance tax is a function of volume and revenues generated from onshore production. On an absolute dollar basis, severance tax decreased by 4% from the first quarter of 2004 to the first quarter of 2005 primarily as a result of the continued benefit of the 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. On a unit of production basis, severance tax was unchanged at $0.10 per Mcfe quarter-over-quarter.

Depreciation, Depletion and Amortization. The increase in our depreciation, depletion and amortization expense for first quarter of 2005 was primarily a result of a higher depletion rate combined with additional expense of $2.9 million resulting from our decision not to exercise our option to acquire an interest in an exploration project in Romania s Carpathian Basin based on our evaluation of the first exploratory well. We decided not to exercise the option and as a result, wrote off our $2.9 million investment in the project. This additional expense added approximately $0.10 per Mcfe to our depletion rate for the first quarter of 2005. In addition to the additional $0.10 per Mcfe, our depletion rate for the first quarter of 2005 of $2.27 per Mcfe is 12% higher than the $2.02 per Mcfe during the first quarter of 2004. The higher rate for the first quarter of 2005 is primarily as a result of a 48% increase in our estimated future development costs at December 31, 2004, as compared to estimates at December 31, 2003.

Asset Retirement Accretion Expense. ARO accretion expense was unchanged at $1.3 million during both the first quarter of 2005 and 2004. The increase of $0.01 per unit of production was due to a decrease in production volume quarter-over-quarter.

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	**2005**	**2004**	**Variance**		**2005**	**2004**	**Variance**	
	(in thousands)							
Gross general and administrative expense	$ 15,962	$ 10,803	$ 5,159	48%	$ 0.53	$ 0.36	$ 0.17	47%
Operating overhead reimbursements	(550)	(513)	(37)	7%	(0.02)	(0.02)		
Capitalized general and administrative	(4,289)	(4,202)	(87)	2%	(0.14)	(0.14)		
General and administrative expense, net	$ 11,123	$ 6,088	$ 5,035	83%	$ 0.37	$ 0.20	$ 0.17	85%

For the first three months of 2005, aggregate general and administrative expenses increased by 48%, or $5.2 million, as compared to the first three months of 2004. Net general and administrative expenses increased by 83%, or $5.0 million, during this period. Of the increase, $5.0 million was attributable to additional expense incurred pursuant to the February 2005 renegotiation of executive employment agreements (see Note 5 Related Party Transactions *Employment Agreements*) with the remaining portion of the increase attributable to incremental stock compensation expense offset in part by a decrease in incentive compensation expense quarter-over-quarter.

For general and administrative expense on a per-unit of production basis, the additional expense related to the renegotiation of employment agreements resulted in a $0.17 per Mcfe increase for the first quarter of 2005. After giving effect to the additional expense, gross general and administrative expense for the first quarter of 2005 would have been $0.36 per Mcfe, unchanged from $0.36 per Mcfe during the first quarter of 2004. Net general and administrative expense would have been $0.20 per Mcfe for the first quarter of 2005, unchanged from $0.20 per Mcfe for the first quarter of 2004.

Other Income and Expense, Interest and Taxes

Other Income and Expense. For the first quarter of 2005, other income and expense includes (i) expense of $2.8 million incurred as a result of a payout settlement at East Cameron 82/83 and (ii) income of $1.3 million related to refunds of prior years severance tax expense. In July 2002, we applied for and received from the Railroad Commission of Texas 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.

	Three Months Ended March 31,			
Interest and Average Borrowings	**2005**	**2004**	**Variance**	
		(in thousands)		
Gross interest	$ 5,424	$ 4,228	$ 1,196	28%
Capitalized interest	(1,990)	(1,941)	(49)	3%
Interest expense, net of capitalized interest	$ 3,434	$ 2,287	$ 1,147	50%
Average borrowings	$ 344,744	$ 281,400	$ 63,344	23%
Average interest rate	5.82%	5.53%	0.29%	5%

During the first quarter of 2005, the increase in gross interest expense is due to an increase in outstanding borrowings under our revolving bank credit facility and an increase in average interest rates associated with our bank debt. Bank borrowings averaged $170.0 million at a rate of 4.6% during the first quarter of 2005 compared to an average of $106.0 million at 3.27% during the first quarter of 2004. Our average bank debt increased during the second half of 2004 and the first quarter of 2005 as we utilized our revolving facility to fund a portion of the asset exchange transaction with KeySpan in June 2004,

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two producing property acquisitions in September and October 2004 and the East Texas acquisition in March 2005. Although the majority of our bank debt bears interest at LIBOR-based rates, we do expect to see an increase in rates during 2005 if the Federal Reserve continues its expected plan to slowly increase Federal interest rates in an effort to curb inflation. Federal rates were increased in February and March 2005, by one quarter of a percent during each period. Capitalized interest is a function of unevaluated properties and the 3% increase during the first quarter of 2005 compared to the first quarter of 2004 corresponds to the increase in our average unevaluated property balance during the first three months of 2005.

Income Tax Provision. Our provision for taxes includes both state and federal taxes. Our current provision for the first quarter of 2005 includes $1.4 million relating to nondeductible excess executive compensation expense incurred as a result of the contract renegotiation payment made to our Chief Executive Officer in February 2005 (see Note 5 Related Party Transactions *Employment Agreements*). Our provision for the first quarter of 2005 includes additional expense of $2.0 million, primarily related to adjustments to estimates for federal and state liabilities.

Liquidity

Capital Requirements

Our principal requirements for capital are to fund our capital investment program and to satisfy our contractual obligations, primarily the repayment of long-term debt and any amounts owing in the period relating to our hedging positions. Our capital investments include the following:

- § Costs of acquiring and maintaining our lease acreage position and our seismic resources;
- § Costs of drilling and completing new natural gas and oil wells;
- § Costs of acquiring additional reserves;
- § Costs of installing new production infrastructure;
- § Costs of maintaining, repairing, and enhancing existing natural gas and oil wells;
- § Costs related to plugging and abandoning unproductive or uneconomic wells; and
- § Indirect costs related to our exploration activities, including payroll and other expense attributable to our exploration professional staff.

On April 26, 2005, our Board of Directors increased our capital expenditure budget for 2005 from an initial level of $446 million to $512 million. The $66 million increase was made in part to accommodate our $31.2 million East Texas acquisition. We are the designated operator of approximately 77% of our wells. Operating allows us the ability to exercise control over the magnitude and timing of our capital program and provides us significant latitude to increase or decrease our spending in response to changes in price, operational developments or acquisition opportunities. 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. Going forward, we have not included property acquisition costs in our capital budget because the size and timing of capital requirements for acquisitions are inherently unpredictable. As the year progresses, we will continue to evaluate our capital spending. Actual levels may vary due to a variety of factors, including drilling results, natural gas prices, economic conditions and future acquisitions.

Our total company capital expenditures during the first three months of 2005 were $146.6 million. We invested $146.3 million in natural gas and oil properties, which included $22.6 million for producing property acquisitions, and we spent $0.3 million for non-oil and gas property and equipment. Non-oil and gas property and equipment includes expenditures to upgrade our information technology systems and office equipment and compares to $0.6 million spent during the first three months of 2004. For the first three months of 2005, we spent 38% offshore and 58% onshore with the balance of 4% on capitalized interest and general and administrative costs. We completed the drilling of 80 gross wells (69.6 net), of which 75%, or 60 (51.7 net), were successful and 25%, or 20 (17.9 net), were unsuccessful, with an additional 8 wells (5.6 net) in progress at March 31, 2005. The following table provides a summary of our capital expenditures for natural gas and oil properties during each of the three-month periods ended March 31, 2005 and 2004.

Natural gas and oil capital expenditures	Three Months Ended March 31, 2005	2004
	(in thousands)	
Producing property acquisitions	$ 22,615	$ 2,700
Leasehold and lease acquisition costs [1]	25,237	13,634
Development	73,223	57,536
Exploration	25,239	10,768
Total natural gas and oil capital expenditures	146,314	84,638
Producing property dispositions	(150)	(13,138)
Net natural gas and oil capital expenditures	$ 146,164	$ 71,500

[1] For the three months ended March 31, 2005 and 2004, leasehold costs include capitalized interest and general and administrative expenses of $6.3 million and $6.1 million, respectively.

Future Commitments

As of March 31, 2005, we had committed to acquire additional East Texas producing properties for $9.2 million, which we paid in April 2005, and have a purchase obligation under an existing seismic license agreement to acquire additional seismic data for up to $7.7 million payable in January 2006. During February 2005, we entered into a one-year contract for a drilling rig in the Uinta Basin. As of March 31, 2005, we do not have any capital leases nor have we entered into any additional long-term contracts for drilling rigs or equipment. The table below provides estimates of the timing of future payments that we were obligated to make based on agreements in place at March 31, 2005. In addition to the contractual obligations listed on the table below, our balance sheet at March 31, 2005, reflects accrued interest payable on our bank credit facility of approximately $57,000 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, and we anticipate making income tax payments of approximately $50 million during 2005.

	Reference	Total	As of March 31, 2005 Payments Due by Period 1 year or less	2 3 years	4 5 years	after 5 years
			(in thousands)			
Contractual Obligations:						
Revolving bank credit facility, due April 2008	Note 2	$ 165,000	$	$	$ 165,000	$
7% senior subordinated notes, due June 2013	Note 2	175,000				175,000
Derivative instruments	Note 1	274,255	193,849	71,997	8,409	
Operating leases	Note 4	6,869	1,170	3,142	2,557	
East Texas producing property acquisition	Note 6	9,246	9,246			

Seismic data purchase	Note 4	7,749	7,749			
Drilling contract	Note 4	3,560	3,560			
		641,679	215,574	75,139	175,966	175,000
Other Long-Term Obligations:						
Asset retirement obligations	Note 1	95,318	2,141	11,754	6,869	74,554
Total contractual obligations and commitments		$ 736,997	$ 217,715	$ 86,893	$ 182,835	$ 249,554

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Capital Resources

We intend to fund our capital expenditure program and contractual commitments through cash flows from our operations and borrowings under our revolving bank credit facility. If a significant acquisition opportunity arises, we may also access public markets for debt or to issue additional equity securities. Our primary sources of cash during the first quarter of 2005 were from funds generated from operations. Cash was used to fund acquisitions, exploration and development expenditures and to reduce debt under our revolving bank credit facility. We made aggregate cash payments of $2 million for interest during the first three months of 2005 with no cash payments for federal or state income taxes during the same three-month period. The table below summarizes the sources of cash during 2005 and 2004.

	Three Months Ended March 31,			
	2005	2004	variance	% change
	(in thousands)			
Net cash provided by operating activities	$ 148,848	$ 128,606	$ 20,242	16%
Net cash (used) for investments in property and equipment	(146,477)	(72,084)	(74,393)	103%
Net cash (used in) provided by financing activities	(7,188)	(45,371)	38,183	-84%
Net (decrease) increase in cash	$ (4,817)	$ 11,151	$ (15,968)	-143%

At March 31, 2005, we had a working capital deficit of $141.2 million, long-term debt of $340 million and $234.6 million of borrowing capacity available under our revolving bank credit facility. The working capital deficit at March 31, 2005, was due to a current liability of $193.8 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 $68.6 million. As a result of higher natural gas prices, the fair value of our open derivative contracts payable within the next 12 months increased by $125.2 million from a liability of $68.1 million at December 31, 2004, to a liability of $193.8 million at March 31, 2005. Corresponding to the increase in the liability, the associated deferred tax asset increased by $44.5 million during this same three-month period. 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 the largest unfavorable mark-to-market position in a high 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 bank credit facility. As a result, we often have a working capital deficit or a relatively small amount of positive working capital, which is typical of companies of our size in the exploration and production industry.

The 16% increase in net cash provided by operating activities during the first three months of 2005 was primarily attributable to fluctuations in operating assets and liabilities, which are caused by the timing of cash receipts and disbursements.

During the first three months of 2005, total long-term debt decreased by a net $15 million, as we used cash generated from operations to repay borrowings under our revolving bank credit facility. Subsequent to March 31, 2005, we repaid an additional $9.0 million under our revolving bank credit facility, reducing outstanding bank borrowings to $156 million as of May 4, 2005. In addition, as a result of rising natural gas prices, we issued letters of credit totaling $3.3 million to further guarantee our performance under open derivative contracts, increasing outstanding letters of credit to $3.7 million as of May 4, 2005.

Access to Capital Markets. In March 2004 and October 2004 we filed shelf registration statements with the SEC for the offering, from time to time, of up to $750 million, on a combined basis, of our common stock, preferred stock, depositary shares and debt securities, or a combination of any of these securities.

We believe that operating cash flow and our credit facility will be adequate to meet our capital and operating requirements for the remaining portion of 2005. 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. Although we have no specific budget for future property acquisitions, should attractive opportunities arise, we believe we could finance the additional capital expenditures with cash on hand, operating cash flow, additional borrowing under our revolving bank credit facility, issuances of additional equity or debt securities or development with industry partners.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements to enhance liquidity and capital resource positions, or for any other purpose. Any future transactions involving off-balance sheet arrangements would be scrutinized and disclosed.

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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. Our sales price 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 Market Risk

At March 31, 2005, total debt was $340 million, of which approximately 51%, or $175 million, is fixed at an interest rate of 7%. The remaining 49% of our total debt balance at March 31, 2005, or $165 million, represents our bank debt that is tied to floating or market interest rates. Fluctuations in floating interest rates will cause our annual interest costs to fluctuate. During the first quarter of 2005, the interest rate on our outstanding bank debt averaged 4.60%. If the balance of our bank debt at March 31, 2005, were to remain constant, a 10% change in market interest rates would impact our cash flow by approximately $189,750 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 a more predictable cash flow, as well as to reduce our exposure to adverse price fluctuations of natural gas. Our derivatives are not held for trading purposes. While the use of hedging arrangements limits the downside risk of adverse price movements, it also limits increases in future revenues as a result of favorable price movements. 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 use are swaps, collars and options, which we generally place with major investment grade financial institutions that we believe are minimal credit risks. We believe that our credit risk related to our natural gas futures and swap contracts is no greater than the risk associated with the 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.

Our hedges are cash flow hedges and qualify for hedge accounting under SFAS 133 and, accordingly, we carry the fair market value of our derivative instruments on the balance sheet as either an asset or liability and defer unrealized gains or losses, net of tax, 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 the hedged production occurs. If any ineffectiveness occurs, amounts are recorded directly to natural gas and oil revenues. During the first three months of 2005 and 2004, we recognized $1.4 million and $1.0 million, respectively, for ineffectiveness. The ineffectiveness was primarily a result of changes at the end of each period in the price differentials between the index price of the derivative contract, which uses a NYMEX index, and the index price for the point of sale for the cash flow that is being hedged, the majority of which is the Houston Ship Channel index.

Subsequent to the balance sheet date and as a result of increases in the market price of natural gas, the fair value of our open derivative contracts increased beyond our available credit limit with one counterparty. As a result, in April 2005, we were required to issue letters of credit totaling $3.3 million to further guarantee our performance on open derivative contracts.

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, 2005 and 2004, and provides the fair value at the end of each period.

	Three Months Ended March 31,	
	2005	**2004**
Change in Fair Value of Derivatives Instruments:	Before Tax (in thousands)	
Fair value of contracts at January 1	$ (75,149)	$ (36,862)
Realized loss on contracts settled	14,175	11,549
(Decrease) in fair value of all open contracts	(213,281)	(58,524)
Net (decrease) increase during period		
Fair value of contracts outstanding at March 31	$ (274,255)	$ (83,837)

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Derivatives in Place as of the Date of Our Report

As of May 4, 2005, the following table summarizes, on a daily basis, our natural gas hedges in place for 2005, 2006, 2007 and 2008. For the remaining nine months of 2005, we have hedged approximately 70% of our estimated production, or a total of 260,000 million British thermal units per day (MMBtu/day).

Year	Transaction Type	Daily Volume (MMBtu/day)	NYMEX Price ($/MMBtu)	Floor Price ($/MMBtu)	Ceiling Price ($/MMBtu)
2005	Swap	20,000	$ 4.75		
2005	Swap	10,000	4.77		
2005	Swap	20,000	4.78		
2005	Swap	20,000	6.15		
2005	Swap	10,000	6.30		
	Total swaps	80,000			
2005	Costless collar	100,000		$ 4.50	$ 5.50
2005	Costless collar	30,000		4.50	6.05
2005	Costless collar	10,000		4.50	6.06
2005	Costless collar	10,000		4.50	6.07
2005	Costless collar	10,000		6.50	10.15
2005	Costless collar	20,000		6.50	10.19
	Total collars	180,000			
Total daily volume 2005		260,000			
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 mark-to-market 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

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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. 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.

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 first quarter of our fiscal year ended December 31, 2005, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Part II. Other Information

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

On April 26, 2005, we held our annual meeting of stockholders. 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	25,221,926	1,949,490
John U. Clarke	25,917,350	1,254,066
David G. Elkins	25,882,983	1,288,433
William G. Hargett	25,533,653	1,637,763
Harold R. Logan, Jr.	25,919,180	1,252,236
Thomas A. McKeever	25,920,280	1,251,136
Stephen W. McKessy	25,918,080	1,253,336
Donald C. Vaughn	25,915,100	1,256,316

2. An amendment to our Restated Certificate of Incorporation increasing the number of authorized shares of common stock, par value $0.01 per share, from 50,000,000 to 100,000,000 shares:

Votes For	Votes Against	Abstained
21,539,994	5,601,533	29,889

3. The ratification and approval of Deloitte & Touche LLP as our independent public accountants for the fiscal year ending December 31, 2005:

Votes For	Votes Against	Abstained
27,100,748	37,174	33,494

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Item 5. Other Information

In accordance with SEC rules, the following information in this Item 5 is provided in lieu of a Current Report on Form 8-K, Item 1.01. Entry into a Material Definitive Agreement and Item 3.03. Material Modification to Rights of Security Holders , that would otherwise be due within four business days after the May 2, 2005 date noted below on which the Rights Agreement was amended.

On May 2, 2005, The Houston Exploration Company (the Company) and The Bank of New York, as Rights Agent, amended the Rights Agreement, dated as of August 12, 2004, by executing the First Amendment to the Rights Agreement (Amendment No. 1), in connection with rights to purchase Series A Junior Participating Preferred Stock of the Company. Amendment No. 1 amends the Rights Agreement as follows: (1) the definition of Acquiring Person set forth in Section 1 of the Rights Agreement is amended to increase the threshold of common stock ownership required for a stockholder to be deemed an Acquiring Person from 10% to 15%; (2) the definition of Exempt Person is amended to delete references to KeySpan Corporation, the Company s former significant stockholder; and (3) Exhibit C to the Rights Agreement, the Summary of Rights to Purchase Shares of Preferred Stock of The Houston Exploration Company, is amended to make conforming changes.

The original Rights Agreement was filed as Exhibit 1 to the Company s Registration Statement on Form 8-A dated August 12, 2004, and is incorporated by reference herein. The foregoing description of Amendment No. 1 is qualified in its entirety by Amendment No. 1, which is attached hereto as Exhibit 4.1 and incorporated by reference herein.

Item 6. Exhibits

EXHIBITS	DESCRIPTION
3.1(1)	Restated Certificate of Incorporation, as amended, including the Certificate of Amendment filed April 26, 2005.
4.1(1)	First Amendment dated as of May 2, 2005, to the Rights Agreement dated as of August 12, 2004 between The Houston Exploration Company and The Bank of New York, as Rights Agent.
10.1(1)	Second Amendment dated effective as of October 8, 2004, to the Amended and Restated Credit Agreement dated April 1, 2004, among The Houston Exploration Company and Wachovia Bank, National Association, as Issuing Bank and Administrative Agent; The Bank of Nova Scotia and Fleet National Bank as Co-Syndication Agents; and BNP Paribas and Comerica Bank as Co-Documentation Agents.
10.2(2)	Employment agreement dated March 10, 2005, between The Houston Exploration Company and John E. Bergeron (filed as exhibit 99.2 to our Current Report on Form 8-K on March 10, 2005, (File No. 001-11899) and incorporated by reference).
10.3(2)	Employment agreement dated April 13, 2005, between The Houston Exploration Company and Jeffrey B. Sherrick (filed as exhibit 99.2 to our Current Report on Form 8-K on April 13, 2005, (File No. 001-11899) and incorporated by reference).
12.1(1)	Computation of ratio of earnings to fixed charges.

21.1[(1)]	Subsidiaries of The Houston Exploration Company.
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 John H. Karnes, 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 John H. Karnes, Chief Financial Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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(1) Filed herewith.

(2) Management contract or compensation plan.

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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
	By: /s/ William G. Hargett
Date: May 4, 2005	William G. Hargett Chairman, President and Chief Executive Officer
	By: /s/ John H. Karnes
Date: May 4, 2005	John H. Karnes Senior Vice President and Chief Financial Officer
	By: /s/ James F. Westmoreland
Date: May 4, 2005	James F. Westmoreland Vice President and Chief Accounting Officer

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Exhibit Index

EXHIBITS	DESCRIPTION
3.1(1)	Restated Certificate of Incorporation, as amended, including the Certificate of Amendment filed April 26, 2005.
4.1(1)	First Amendment dated as of May 2, 2005, to the Rights Agreement dated as of August 12, 2004 between The Houston Exploration Company and The Bank of New York, as Rights Agent.
10.1(1)	Second Amendment dated effective as of October 8, 2004, to the Amended and Restated Credit Agreement dated April 1, 2004, among The Houston Exploration Company and Wachovia Bank, National Association, as Issuing Bank and Administrative Agent; The Bank of Nova Scotia and Fleet National Bank as Co-Syndication Agents; and BNP Paribas and Comerica Bank as Co-Documentation Agents.
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(1) Filed herewith.

(2) Management contract or compensation plan.