HOUSTON EXPLORATION CO
Form 10-Q
August 07, 2003

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934

FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2003

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934

FOR THE TRANSITION PERIOD FROM ________ TO ________

COMMISSION FILE NO. 001-11899

THE HOUSTON EXPLORATION COMPANY
(EXACT NAME OF REGISTRANT AS SPECIFIED IN ITS CHARTER)

DELAWARE	22-2674487
(STATE OR OTHER JURISDICTION OF INCORPORATION OR ORGANIZATION)	(IRS EMPLOYER IDENTIFICATION NO.)

1100 LOUISIANA STREET, SUITE 2000
HOUSTON, TEXAS 77002-5215
(ADDRESS OF PRINCIPAL EXECUTIVE OFFICES AND 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 [X] No [ ]

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Securities Exchange Act of 1934).
Yes [X] No [ ]

As of August 6, 2003, 31,078,668 shares of Common Stock, par value $.01 per share, were outstanding.

THE HOUSTON EXPLORATION COMPANY

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FACTORS AFFECTING FORWARD LOOKING STATEMENTS

All of the estimates and assumptions contained in this Quarterly Report constitute forward looking statements as that term is defined in Section 27A of the Securities Act of 1993 and Section 21E of the Securities Exchange Act of 1934. These forward-looking statements generally are accompanied by words such as "anticipate," "believe," "expect," "estimate," "project" or similar expressions. All statements under the caption "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations" relating to our anticipated capital expenditures, future cash flows and borrowings, pursuit of potential future acquisition opportunities and sources of funding for exploration and development are forward looking statements. Although we believe that these forward-looking statements are based on reasonable assumptions, our expectations may not occur and the anticipated future results may not be achieved. A number of factors could cause our actual future results to differ materially from the anticipated future results expressed in this Quarterly Report. 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, our ability to meet our substantial capital requirements, our substantial outstanding indebtedness, the uncertainty of estimates of natural gas and oil reserves and production rates, our ability to replace reserves, and our hedging activities. For additional discussion of these 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.

In this Quarterly Report, unless the context requires otherwise, when we refer to "we", "us" or "our", we are describing The Houston Exploration Company and its subsidiary on a consolidated basis.

PART I. FINANCIAL INFORMATION
ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

THE HOUSTON EXPLORATION COMPANY
CONSOLIDATED BALANCE SHEETS
(IN THOUSANDS, EXCEPT SHARE DATA)

	JU 2 (UNA
ASSETS:	
Cash and cash equivalents	$
Accounts receivable	
Accounts receivable -- Affiliate	
Derivative financial instruments	
Inventories	
Prepayments and other	
Total current assets	
Natural gas and oil properties, full cost method	
Unevaluated properties	
Properties subject to amortization	2,
Other property and equipment	
	2,
Less: Accumulated depreciation, depletion and amortization	
	1,
Derivative financial instruments	
Other non-current assets	
Other assets	
TOTAL ASSETS	$ 1,
LIABILITIES:	

Accounts payable and accrued expenses	$
Notes payable	
Derivative financial instruments	
Asset retirement obligation	

Total current liabilities	
Long-term debt and notes	
Derivative financial instruments	
Deferred federal income taxes	
Asset retirement obligation	
Other deferred liabilities	

TOTAL LIABILITIES	
COMMITMENTS AND CONTINGENCIES (SEE NOTE 3)	
STOCKHOLDERS' EQUITY:	
Common Stock, $.01 par value, 50,000,000 shares authorized and 31,078,668 shares issued and outstanding at June 30, 2003 and 30,954,018 shares issued and outstanding at December 31, 2002, respectively	
Additional paid-in capital	
Unearned compensation	
Retained earnings	
Accumulated other comprehensive income	

TOTAL STOCKHOLDERS' EQUITY	

TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 1,
	====

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)

	THREE MONTHS ENDED JUNE 30,		SI
	2003	2002	2003
	---------	---------	-------
	(UNAUDITED)		(
REVENUES:		(restated)	
Natural gas and oil revenues	$ 120,388	$ 85,588	$ 248,7
Other	244	367	8
	---------	---------	-------
Total revenues	120,632	85,955	249,6
OPERATING EXPENSES:			

Lease operating	11,669	7,886	23,3
Severance tax	3,222	2,791	7,5
Transportation expense	2,696	2,227	5,1
Asset retirement accretion expense	826	--	1,6
Depreciation, depletion and amortization	47,724	42,044	93,3
General and administrative, net	4,204	2,488	8,0
Total operating expenses	70,341	57,436	139,1
Income from operations	50,291	28,519	110,4
Other (income) expense	3,616	--	(6,9
Interest expense, net	2,160	1,644	4,4
Income before income taxes	44,515	26,875	113,0
Provision for taxes	15,592	9,221	39,6
INCOME BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	$ 28,923	$ 17,654	$ 73,3
Cumulative effect of change in accounting principle ..	--	--	(2,7
NET INCOME	$ 28,923	$ 17,654	$ 70,6
EARNINGS PER SHARE:			
NET INCOME PER SHARE - BASIC			
Income before cumulative effect of change in accounting principle	$ 0.93	$ 0.58	$ 2.
Cumulative effect of change in accounting principle	--	--	(0.
Net income per share -- basic	$ 0.93	$ 0.58	$ 2.
NET INCOME PER SHARE -- FULLY DILUTED			
Income before cumulative effect of change in accounting principle	$ 0.93	$ 0.57	$ 2.
Cumulative effect of change in accounting principle	--	--	(0.
Net income per share -- fully diluted	$ 0.93	$ 0.57	$ 2.
Weighted average shares outstanding -- basic	30,987	30,516	30,9
Weighted average shares outstanding -- fully diluted..	31,095	30,854	31,0

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)

SIX MONTHS
2003

	(UNA
OPERATING ACTIVITIES:	
Net income	$ 70,620
Adjustments to reconcile net income to net cash provided by operating activities:	
Depreciation, depletion and amortization	93,378
Deferred income tax expense	39,573
Asset retirement accretion expense	1,652
Debt extinguishment expense	1,626
Stock compensation expense	101
Cumulative effect of change in accounting principle	2,772
Changes in operating assets and liabilities:	
Increase in accounts receivable	(34,163)
Increase in inventories	(115)
Decrease in prepayments and other	7,308
(Increase) decrease in other assets	(12,398)
Increase (decrease) in accounts payable and accrued expenses	13,910
Increase (decrease) in other liabilities	1,348
Net cash provided by operating activities	185,612
INVESTING ACTIVITIES:	
Investment in property and equipment	(138,348)
Dispositions	--
Net cash used in investing activities	(138,348)
FINANCING ACTIVITIES:	
Proceeds from long term borrowings	228,000
Repayments of long term borrowings	(185,000)
Debt issuance costs	(4,108)
Proceeds from issuance of common stock from exercise of stock options	2,460
Proceeds from issuance of common stock	79,200
Repurchase of common stock	(79,200)
Net cash provided by financing activities	41,352
Increase in cash and cash equivalents	88,616
Cash and cash equivalents, beginning of period	18,031
Cash and cash equivalents, end of period	$ 106,647
SUPPLEMENTAL INFORMATION:	
Cash paid for interest	$ 6,439
Cash paid for taxes	$ 10,900

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

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

NOTE 1 -- SUMMARY OF ORGANIZATION AND SIGNIFICANT ACCOUNTING POLICIES

Organization

We are an independent natural gas and oil company engaged in the exploration, development, exploitation and acquisition of domestic natural gas and oil properties. Our operations are primarily focused in South Texas, offshore in the shallow waters of the Gulf of Mexico and in the Arkoma Basin of Oklahoma and Arkansas with additional production located in East Texas, South Louisiana and West Virginia.

Principles of Consolidation

The consolidated financial statements include the accounts of The Houston Exploration Company and its wholly owned subsidiary, Seneca Upshur Petroleum Company (collectively the "Company"). All intercompany balances and transactions have been eliminated.

Interim Financial Statements

Our balance sheet at June 30, 2003 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. 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. The balance sheet at December 31, 2002 is derived from the December 31, 2002 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, 2002.

In the opinion of our management, all adjustments, consisting of normal recurring accruals, necessary to present fairly the information in the accompanying financial statements have been included. The results of operations for such interim periods are not necessarily indicative of the results for the full year.

Use of Estimates and Restatements

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 and our full cost ceiling test limitation.

For all periods presented, we applied Emerging Issues Task Force ("EITF") No. 00-10 "Accounting for Shipping and Handling Fees and Costs." Pursuant to our application of EITF No. 00-10, transportation expenses previously reflected as a reduction to natural gas and oil revenues for the three months and six months ended June 30, 2002 were added back to revenues and reflected as a separate component of operating expense and accordingly, the

Statement of Operations has been restated for the three month and six month periods ended June 30, 2002. The application of EITF No. 00-10 has no effect on income from operations or net income. The table below provides a summary of the effects of application of EITF No. 00-10 for amounts reported in for the three month and six month periods ended June 30, 2002.

	THREE MONTHS ENDED JUNE 30, 2002		SIX MONTHS ENDE JUNE 30, 2002	
	RESTATED	PREVIOUSLY REPORTED	RESTATED	PREVI REPO
Natural gas and oil revenues	$ 85,588	$ 83,361	$160,210	$155
Total revenues	85,955	83,728	160,771	156
Transportation expenses	2,227	--	4,403	
Total operating expenses	57,436	55,209	111,861	107
Income from operations	28,519	28,519	48,910	48
Net income	17,654	17,654	30,188	30
Natural gas price:				
Average realized price (per Mcf)	$ 3.28	$ 3.19	$ 3.14	$
Average unhedged price (per Mcf)	3.28	3.19	2.79	

Derivative Instruments

Our hedges are designated cash flow hedges and qualify for hedge accounting under Statements of Financial Accounting Standards ("SFAS") No. 133, as amended, "Accounting for Derivative Instruments and Hedging Activities" 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 ineffectiveness occurs, amounts are recorded directly to other income or expense.

Net Income per Share

Basic earnings per share ("EPS") 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. Diluted EPS assumes and gives pro forma effect to the conversion of all potentially dilutive securities and is calculated by dividing net income, as adjusted, by the weighted average number of shares of common stock outstanding plus all potentially dilutive securities.

	THREE MONTHS ENDED JUNE 30,		S
	2003	2002	20
	(IN THOUSANDS, EXCEPT PE		
NUMERATOR:			
Income before cumulative effect of change in accounting principle	$28,923	$17,654	$ 7
Cumulative effect of change in accounting principle	--	--	(
Net income	$28,923	$17,654	$ 7
DENOMINATOR:			
Weighted average shares outstanding	30,987	30,516	3
Add dilutive securities: Stock options	108	338	
Total weighted average shares outstanding and dilutive securities	31,095	30,854	3
EARNINGS PER SHARE - BASIC:			
Income before cumulative effect of change in accounting principle	$ 0.93	$ 0.58	$
Cumulative effect of change in accounting principle	--	--	
Net income per share - basic	$ 0.93	$ 0.58	$
EARNINGS PER SHARE - FULLY DILUTED:			
Income before cumulative effect of change in accounting principle	$ 0.93	$ 0.57	$
Cumulative effect of change in accounting principle	--	--	
Net income per share - fully diluted	$ 0.93	$ 0.57	$

For the three months ended June 30, 2003 and 2002, the calculation of shares outstanding for fully diluted EPS does not include the effect of outstanding stock options to purchase 1,893,611 and 1,328,719 shares, respectively, because the exercise price of these shares was greater than the average market price for the year, which would have an antidulitive effect on EPS. For the six month periods ended June 30, 2003 and June 30, 2002, fully diluted EPS does not include the effect of outstanding stock options to purchase 1,898,559 shares and 1,292,234 shares, respectively, because inclusion would have been antidulitive.

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

Comprehensive Income

The table below summarizes our Comprehensive Income for the three month and six month periods ended June 30, 2003 and 2002, respectively.

	THREE MONTHS ENDED JUNE 30, 2003	THREE MONTHS ENDED JUNE 30, 2002
		(IN THO
Net income	$ 28,923	$ 17,654
Other comprehensive income, net of taxes:		
Unrealized gain (loss) on derivative instruments	2,597	(2,157)
Comprehensive income	$ 31,520	$ 15,497

Stock Option Expense

On January 1, 2003, we adopted the fair value expense recognition provisions of SFAS No. 123 "Accounting for Stock-Based Compensation" and as amended by SFAS No. 148, "Accounting for Stock-Based Compensation - Transition and Disclosure." Under the fair value method, compensation expense for stock options is recognized when stock options are issued. SFAS No. 148 proposes three alternative transition methods for a voluntary change to the fair value method under SFAS No. 123:

- Prospective Method - recognize fair value expense for all awards granted in the year of adoption but not previous awards;

- Modified Prospective Method - recognize fair value expense for the unvested portion of all stock options granted, modified, or settled since 1994 (i.e., the unvested portion of the prior awards or those granted in the year of adoption must be recorded using the fair value method); and

- Retroactive Restatement Method - similar to the Modified Prospective Method except that all prior periods are restated.

We adopted SFAS No. 123 using the Prospective Method, and as a result, we now recognize as compensation expense the fair value of all stock options issued subsequent to December 31, 2002. For the three and six month periods ended June 30, 2003, we recognized compensation expense of $44,000 and $58,000 for stock options granted during the period.

Prior to our January 1, 2003 adoption of SFAS No. 123, we accounted for the incentive stock plans using the intrinsic value method prescribed under Accounting Principles Board Opinion No. 25 and accordingly we did not recognize compensation expense for stock options granted. Had stock options been accounted for using the fair value method as recommended in SFAS No. 123, compensation expense would have had the following pro forma effect on our net income and earnings per share for the three month and six month periods ended June 30, 2003 and 2002.

	THREE MONTHS ENDED JUNE 30, 2003	THREE MONTHS ENDED JUNE 30, 2002
Net income - as reported	$ 28,923	$ 17,654
Add: Stock-based compensation expense included in net income, net of tax	43	14
Less: Stock-based compensation expense using fair value method, net of tax	(1,102)	(1,181)
Net income - pro forma	$ 27,864	$ 16,487
Net income per share - as reported	$ 0.93	$ 0.58
Net income per share - fully diluted - as reported	0.93	0.57
Net income per share - pro forma	$ 0.90	$ 0.54
Net income per share - fully diluted - pro forma	0.90	0.53

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

Asset Retirement Obligations

On January 1, 2003, we adopted SFAS No. 143, "Accounting for Asset Retirement Obligations," which addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. For us, asset retirement obligations represent the systematic, monthly accretion and depreciation of future abandonment costs of tangible assets such as platforms, wells, service assets, pipelines, and other facilities. SFAS No. 143 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, a gain or loss is recognized. Under our previous accounting method, we included estimated future costs of abandonment and dismantlement in our full cost amortization base and amortized these costs as a component of our depletion expense.

Pursuant to the January 1, 2003 adoption of SFAS No. 143 we:

- recognized a charge to income during the first quarter of 2003 of $2.8 million, net of tax, for the cumulative effect of the change in accounting principle;

- increased our total liabilities by $57.2 million to record the asset retirement obligations ("ARO");

- increased our assets by $42.5 million to add the asset retirement costs to the carrying amount of our natural gas and oil properties; and

- reduced our accumulated depreciation, depletion and amortization by $10.4 million for the amount of expense previously recognized.

Adopting SFAS No. 143 had no impact on our reported cash flows. The following table describes on a pro forma basis our asset retirement liability as if SFAS No. 143 had been adopted on January 1, 2002. The ARO liability at June 30, 2003 and December 31, 2002 includes amounts classified as both current and long-term.

	2003	2002
ARO liability at January 1, ...	$57,197	$45,759
Additions from drilling	2,962	4,397
ARO accretion expense	1,652	1,322
ARO liability at June 30, ...	$61,811	$51,478

The following table describes the pro forma effect on net income and earnings per share for the three months and the six months ended June 30, 2002 as if SFAS No. 143 had been adopted on January 1, 2002.

	Three Months Ended June 30, 2002	Six Months Ended June 30, 2002
Net income - as reported	$ 17,654	$ 30,188
Less: ARO accretion expense, net of tax	(430)	(860)
Net income - pro forma	$ 17,224	$ 29,328
Earnings per share:		
Basic - as reported	$ 0.58	$ 0.99
Fully diluted - as reported	0.57	0.98
Basic - pro forma	0.56	0.96
Fully diluted - pro forma	0.56	0.95

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

Recent Accounting Pronouncements

In April 2002, the Financial Accounting Standards Board ("FASB") issued SFAS No. 145, "Rescission of FASB Statements No. 4, No. 44, and No. 64, Amendment to FASB Statement No. 13 and Technical Corrections." SFAS No. 145 streamlines the reporting of debt extinguishments and requires that only gains and losses from extinguishments meeting the criteria in Accounting Policies Board Opinion No. 30 would be classified as extraordinary. Thus, gains or losses arising from extinguishments that are part of a company's recurring operations would not be reported as an extraordinary item. SFAS No. 145 is effective for fiscal years beginning after May 15, 2002. Our adoption of SFAS No. 145 on January 1, 2003 had no effect on our financial statements.

In June 2002, FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities" which addresses accounting and reporting for costs associated with exit or disposal activities and nullifies EITF Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." SFAS No. 146 requires that a liability for a cost associated with an exit or disposal activity be recognized when the liability is incurred. Under Issue 94-3, a liability for an exit cost was recognized at the date of an entity's commitment to an exit plan. Under SFAS No. 146, fair value is the objective for initial measurement of the liability. SFAS No. 146 is effective for exit or disposal activities that are initiated after December 31, 2002. Our adoption of SFAS No. 146 on January 1, 2003 had no effect on our financial statements.

In November 2002, FASB issued Financial Interpretation ("FIN") No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." FIN 45 requires certain guarantees to be recorded at fair value, which is different from the current practice of recording a liability only when a loss is probable and reasonably estimable, as those terms are defined in SFAS No. 5, "Accounting for Contingencies." FIN 45 has a dual effective date. The initial recognition and measurement provisions are applicable on a prospective basis to guarantees issued or modified after December 31, 2002. The disclosure requirements in the interpretation are effective for financial statements for interim or annual periods ending after December 15, 2002. As of our December 31, 2002 and March 31, 2003 balance sheet dates, we did not have any guarantees of indebtedness of others and as a result, our adoption of FIN 45 did not have an effect on our financial statements.

On April 30, 2003, FASB issued SFAS 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities," which amends and clarifies accounting for derivative instruments, including certain derivative instruments embedded in other contracts, and hedging activities under SFAS No. 133. The new guidance amends SFAS 133 for decisions made:

- As a part of the Derivatives Implementation Group process that effectively required amendments to SFAS 133;

- In connection with other FASB projects dealing with financial instruments; and

- Regarding implementation issues raised in relation to the application of the definition of a derivative, particularly regarding the meaning of an "underlying" and the characteristics of a derivative that contains financing components.

The amendments set forth in SFAS 149 are intended to improve financial reporting by requiring that contracts with comparable characteristics be accounted for similarly. In particular, SFAS 149 clarifies the circumstances under which a contract with an initial net investment meets the characteristics of a derivative as discussed in SFAS 133. In addition, SFAS 149 clarifies when a derivative contains a financing component that warrants special reporting is the statement of cash flows. SFAS 149 amends certain other existing pronouncements, resulting in more consistent reporting of contracts that are derivatives in their entirely or that contain embedded derivatives that warrant separate accounting.

SFAS 149 is effective for contracts entered into or modified after June 30, 2003, except as stated below, and for hedging relationships designated after June 30, 2003. The guidance should be applied prospectively.

The provisions of SFAS 149 that relate to SFAS 133 Implementation Issues that have been effective for fiscal quarters that began prior to June 15, 2003 should continue to be applied in accordance with their respective effective dates. In addition, certain provisions relating to forward purchases or sales of "when issued" securities or other securities that do not yet exist should be applied to existing contracts as well as new contracts entered into after June 30, 2003. Our adoption of SFAS 149 will not have an effect on our financial statements.

On May 15, 2003, FASB issued SFAS 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity," which aims to eliminate diversity in practice by requiring that the following three types of "freestanding" financial instruments be reported as liabilities by their issuers:

- Mandatorily redeemable instruments (i.e., instruments issued in the form of shares that unconditionally obligate the issuer to redeem the shares for cash or by transferring other assets);

- Forward purchase contract, written put options, and other financial instruments not in the form of shares that either obligate or may obligate the issuer to repurchase its equity shares and settle its obligation for cash or by transferring other assets; and,

- Certain financial instruments that include an obligation that (1) the issuer may or must settle by issuing a variable number of its equity shares and (2) has a "monetary value" at inception that (a) is fixed, (b) is tied to a market index or other benchmark (something other than the fair value of the issuer's equity shares), or (c) varies inversely with the fair value of the equity shares (e.g., a written put option).

Until this pronouncement was issued, these types of instruments have been variously presented by their issuers as liabilities, as part of equity, or between the liabilities and equity sections (sometimes referred to as "mezzanine" reporting) in the statement of financial position.

For our company, the provisions of SFAS 150, which also include a number of new disclosure requirements, are effective for (1) instruments interest into or modified after May 31, 2003 and (2) pre-existing instruments as of the beginning of the first interim period that commences after June 15, 2003. Our adoption of SFAS 150 has had no effect on our financial statements.

NOTE 2 -- LONG-TERM DEBT AND NOTES

	JUNE 30, 2003	DECEMBER 31, 2002
	(in thousands)	
SENIOR DEBT:		
Revolving bank credit facility, due July 2005	$ 20,000	$152,000
SUBORDINATED DEBT:		
8 5/8% Senior Subordinated Notes, due January 2008	100,000	100,000
7% Senior Subordinated Notes, due June 2013	175,000	--
Total debt and notes	$295,000	$252,000
Less: amounts classified as current		
8 5/8% Senior Subordinated Notes, called for redemption July 11, 2003	100,000	--
Total long-term debt and notes	$195,000	$252,000

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. The market value of our $175 million 7% senior subordinated notes issued June 10, 2003 was estimated at 100% of the carrying value or $175 million. At June 30, 2003, the quoted market value of our $100 million of 8 5/8% senior subordinated notes was 104.715% of the $100 million carrying value or $104.7 million as a result of our announcement on June 10, 2003 to call for early redemption the 8 5/8% notes. The premium for early redemption of 4.313% or $4.3 million was paid on July 11, 2003.

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 as documentation agent. The credit facility provides us with a commitment of $300 million which may be increased at our request and with prior approval from Wachovia to a maximum of $350 million by adding one or more lenders or by allowing one or more lenders to increase their commitments. The credit facility is subject to borrowing base

limitations. Our current borrowing base is $300 million and is redetermined semi-annually, with the next redetermination scheduled for October 1, 2003. Up to $25 million of the borrowing base is available for the issuance of letters of credit. The credit facility matures July 15, 2005, is unsecured and with the exception of trade payables, ranks senior to all of our existing debt. At June 30, 2003, $20 million in borrowings were outstanding under the credit facility and $9.4 million was outstanding in letter of credit obligations. Subsequent to June 30, 2003, we repaid all outstanding borrowings of $20 million under our revolving bank credit facility and we reduced our letter of credit obligations to $0.4 million. As of the date of this report, outstanding borrowings and letter of credit obligations under our revolving bank credit facility total $0.4 million.

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% 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 negative covenants that place restrictions and limits on, among other things, the incurrence of debt, guaranties, liens, leases and certain investments. The credit facility also restricts and limits 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 70% of our natural gas production during any 12-month period.

As of June 30, 2003 and December 31, 2002, we were in compliance with all covenants.

Senior Subordinated Notes

7% Senior Subordinated Notes due June 15, 2013. 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 which 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;
- 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 subsidiary to make certain distributions or payments; or
- guarantees by our subsidiary of certain indebtedness.

In addition, upon the occurrence of a change of control, 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.

A "change of control" is:

- the direct or indirect acquisition by any person, other than KeySpan or its affiliates, of beneficial ownership of 35% or more of total voting power as long as KeySpan and its affiliates own less than the acquiring person;
- the sale, lease, transfer, conveyance or other disposition, other than by way of merger or consolidation, in one or a series of related transactions, of all or substantially all of our assets to a third party other than KeySpan or its affiliates;
- the adoption of a plan relating to our liquidation or

dissolution; or

- if, during any period of two consecutive years, individuals who at the beginning of the period constituted our board of directors, including any new directors who were approved by a majority vote of directors then in office who were either directors at the beginning of the two-year period or who were previously so approved, cease for any reason to constitute a majority of the members then in office.

Pursuant to a registration rights agreement relating to the notes among us and the initial purchasers, we have agreed to:

- file a registration statement with the SEC with respect to an offer to exchange the notes for new notes issued in a registered offering which will have terms identical in all material respects to the notes, except that the registered notes will not contain terms with respect to transfer restrictions or payment of liquidated damages, within 90 days following the original issue date of the notes;

- use or reasonable best efforts to cause the exchange offer registration statement to become effective under the Securities Act of 1934 within 180 days after June 10, 2003, the original issue date of the notes, and ;

- use or reasonable best efforts to complete the exchange offer with 30 business days after the SEC declares the exchange offer registration statement effective.

We received $170.9 million in net proceeds from the issuance of the $175 million 7% senior subordinated notes. A portion of the net proceeds was used to repay the aggregate principal of $100 million on the 8 5/8% senior subordinated notes together with a premium of $4.3 million for early redemption. The remaining portion of the net proceeds was used to repay $60 million in outstanding borrowings on our revolving bank credit facility with the balance of approximately $6.6 million being applied to working capital, a portion of which was utilized in July to fund the payment of $4.6 million in accrued interest due on the $100 million 8 5/8% notes.

8 5/8% Senior Subordinated Notes due January 1, 2008. On July 11, 2003, we redeemed our $100 million 8 5/8% senior subordinated notes due January 1, 2008. The $100 million 8 5/8% senior subordinated notes were issued on March 2, 1998. The notes bore interest at a rate of 8 5/8% per annum with interest payable semi-annually on January 1 and July 1. The $100 million 8 5/8% notes were redeemable, at our option, in whole or in part, at any time on or after January 1, 2003 at a price equal to 100% of the principal amount plus accrued and unpaid interest, if any, plus a specified premium which decreases yearly from 4.313% in 2003 to 0% in 2006. The redemption and payment of the call premium were funded with a portion of the proceeds received from our June 10, 2003 private placement of the $175 million 7% senior subordinated notes due June 15, 2013. Upon closing of the private placement of the $175 million 7% senior subordinated notes on June 10, 2003, the $100 million 8 5/8% notes were called. At June 30, 2003 and pursuant to the early redemption of the $100 million notes, we incurred debt extinguishment expenses totaling $5.9 million ($3.9 million net of tax) consisting of the call premium of $4.3 million together with a non-cash charge of $1.6 million for the write-off of the balance of the unamortized issue costs. The debt extinguishment expenses of $5.9 million are included in the line item "Other (Income) Expense" on the Statement of Operations for the three and the six months ended June 30, 2003.

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

NOTE 3 -- COMMITMENTS AND CONTINGENCIES

Severance Tax Refund

During 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. The "high-cost/tight-gas formation" designation will allow us to receive an abatement of severance taxes for qualifying wells in various fields. For qualifying wells, production will be either exempt from tax or taxed at a reduced rate until certain capital costs are recovered. For qualifying wells, we will also be entitled to a refund of severance taxes paid during a designated prior 48-month period. Applications for refund are submitted on a well-by-well basis to the State Comptroller's Office and due to timing of the acceptance of applications, we are unable to project the 48-month look-back period for qualifying refunds. We currently estimate that the total refund will be between $18 million to $24.5 million ($12 million to $15.9 million, net of tax), although we can provide no assurances that the actual total refund amount will fall within our current estimate. Since the beginning of the fourth quarter of 2002, we have recorded refunds totaling $23.3 million ($15.1 million net of tax). Refunds recorded during 2003 total $12.9 million ($8.4 million net of tax) of which $2.3 million ($1.5 million net of tax) were recorded during the second quarter. Currently, we estimate that we could record additional refunds of up to $1.2 million ($0.8 million net of tax). Our receivables at June 30, 2003 include $28.2 million in gross refunds of which approximately $19.4 million relates to our working interest with the balance owed to third party royalty interests. Subsequent to June 30, 2003, we received a check from the State of Texas for $19.7 million that will be applied to the receivable for severance tax refunds.

Legal Proceedings

On August 18, 2002, a complaint styled Victor Ramirez, Santiago Ramirez, Jr., Oswaldo H. Ramirez and Javier Ramirez as Co-Trustees of the Ramirez Mineral Trust v. The Houston Exploration Company, cause number 5,207, was filed in the district court of the 49th Judicial District in Zapata County, Texas. The complaint alleges that we trespassed by drilling the No. 7 RMT well to a depth in excess of our lease rights and commingled production by producing from the excess depth. The plaintiffs claim damages for trespass and conversion in excess of $6 million and further seek to recover exemplary damages in excess of $18 million. We are currently unable to predict the outcome of the claim.

We are involved from time to time in various other claims and lawsuits incidental to our business. In the opinion of management, the ultimate liability, if any, in these other matters will not have a material adverse effect on our financial position or results of operations.

NOTE 4 -- RELATED PARTY TRANSACTIONS

Issuance of 3,000,000 Shares to the Public and Concurrent Repurchase of 3,000,000 Shares from KeySpan

In connection with our initial public offering in September 1996, we entered into a registration rights agreement with KeySpan pursuant to which we are obligated, at KeySpan's election, to facilitate KeySpan's sale of its shares of Company stock by registering the shares under the Securities Act of 1933 and assisting in KeySpan's selling efforts. During February of 2003, KeySpan notified us of its desire to sell 3,000,000 shares of their Company stock. For the mutual convenience of the parties, we elected to effect KeySpan's sale through our pre-existing registration statement rather than filing a separate, new registration statement for KeySpan. To accomplish the transaction, we simultaneously sold 3,000,000 newly issued shares of Company stock in a public offering for net proceeds of $26.40 per share, or an aggregate $79.2 million, and bought a like number of KeySpan's shares of Company stock for the same price per share. We cancelled the 3,000,000 shares acquired from KeySpan immediately following the repurchase. KeySpan reimbursed us for all costs and expenses, and the transaction had no impact on our capitalization. The transaction was evidenced in a stock purchase agreement, dated February 26, 2003. Our Board of Directors approved the transaction in principle and delegated to a special, independent committee of the Board plenary authority to negotiate the terms of, and finally approve or veto, the transaction. In finally approving the terms of the stock purchase agreement, the independent committee determined that the agreement was consistent with our pre-existing obligations under our registration rights agreement and that issuing the shares under our existing registration statement was in the best interests of our public stockholders to facilitate the prompt and orderly disposition of the shares. As a result of the transactions, KeySpan's interest in our outstanding shares decreased from 66% to 56%.

Acquisition of KeySpan Joint Venture Assets

In October 2002, we purchased from KeySpan a portion of the assets developed under the joint exploration agreement with KeySpan Exploration & Production, LLC, a subsidiary of KeySpan (see below discussion of KeySpan Joint Venture). The acquisition consisted of interests averaging between 11.25% and 45% in 17 wells covering eight of the twelve blocks that were developed under the joint exploration agreement from 1999 through 2002. The interests purchased were in the following blocks: Vermilion 408, East Cameron 81 and 84, High Island 115, Galveston Island 190 and 389, Matagorda Island 704 and North Padre Island 883. KeySpan has retained its 45% interest in four blocks: South Timbalier 314 and 317 and Mustang Island 725 and 726 as these blocks are in various stages of development. KeySpan has committed to continued participation in the ongoing development of these blocks which includes the completion of the platform and production facilities at South Timbalier 314/317 together with possible further developmental drilling at both South Timbalier 314/317 and Mustang Island 725/726. As of September 1, 2002, the effective date of the purchase, the estimated proved reserves associated with the interests acquired were 13.5 Bcfe. The $26.5 million purchase price was paid in cash and financed with borrowings under our revolving credit facility. Subsequent purchase price adjustments totaled $1.2 million. Our acquisition of the properties was accounted for as a transaction between entities under common control. As a result, the excess fair value of the properties acquired of $3.1 million ($2.0 million net of tax) was treated as a capital contribution from KeySpan and recorded as an increase to additional paid-in capital during the fourth quarter of 2002.

Our Board of Directors appointed a special committee, comprised entirely of independent directors, to review the proposed transaction with KeySpan. For assistance, the special committee retained special outside legal counsel as well as the financial advisory firm of Petrie Parkman & Co. In addition, the special committee discussed the history and terms of the transaction with our senior management. After completing its review, the special committee unanimously concluded that the transaction was advisable and in our best interests and that the terms of the transaction were at least as favorable to us as terms that would have been obtainable at the time in a comparable transaction with an unaffiliated party. In reaching its decision, the special committee considered numerous factors in consultation with its financial and legal advisors. The special committee also took into account the opinion delivered to it by Petrie Parkman & Co. to the effect that the consideration to be paid by us in the transaction was fair to us from a financial point of view.

KeySpan Joint Venture

Effective January 1, 1999, we entered into a joint exploration agreement with KeySpan Exploration & Production, LLC, a subsidiary of KeySpan, to explore for natural gas and oil over an initial two-year term expiring December 31, 2000. Under the terms of the joint venture, we contributed all of our then undeveloped offshore acreage to the joint venture and we agreed that KeySpan would receive 45% of our working interest in all prospects drilled under the program. KeySpan paid 100% of actual intangible drilling costs for the joint venture up to a specified maximum. Further, KeySpan paid 51.75% of all additional intangible drilling costs incurred and we paid 48.25%. Revenues are shared 55% to Houston Exploration and 45% to KeySpan.

Effective December 31, 2000, KeySpan and Houston Exploration agreed to end the primary or exploratory term of the joint venture. As a result, KeySpan has not participated in any of our offshore exploration prospects unless the project involved the development or further exploitation of discoveries made during the initial term of the joint venture. During the first half 2003, KeySpan spent approximately $6.8 million, of which $3.8 million was spent during the second quarter, for capital costs associated with its working interests in properties developed under the joint venture. Costs incurred during 2003 were related to the installation of production facilities at South Timbalier 314/317 and the completion of the initial two exploratory wells that were brought on-line during the first quarter of 2003. In addition, during the second quarter of 2003, KeySpan participated in the drilling of a third well on the property. During the corresponding six month and three month periods of 2002, KeySpan spent $14.6 million and $5.1 million, respectively.

Sale of Section 29 Tax Credits

In June 2003, we repurchased, for $2.6 million, certain interests in producing wells that were sold in January 1997 to a subsidiary of KeySpan under an agreement designed to monetize tax credits available under Section 29 of the Internal Revenue Code. Section 29 provides for a tax credit from non-conventional fuel sources such as oil produced from shale and tar sands and natural gas produced from geopressured brine, Devonian shale, coal seams and tight sands formations. The wells subject to the agreement are located in West Virginia, Oklahoma and East Texas and produce from formations that qualify for Section 29 tax credits. Pursuant to the agreement, KeySpan acquired an economic interest in wells that qualified for the tax credits and, in exchange, we:

- retained a volumetric production payment and a net profits interest of 100% in the properties;

- received a cash down payment of $1.4 million; and

- receive a quarterly payment of $0.75 for every dollar of tax credit utilized.

During the term of the agreement, we managed and administered the daily operations of the properties in exchange for an annual management fee of $100,000. The agreement expired December 31, 2002 and as a result, we were required to repurchase the interests in the producing wells from KeySpan. Subsequent to the repurchase, ownership of the tax credits reverted back to us. The income statement effect, representing benefits received from Section 29 tax credits, was a benefit of $0.2 million and $0.3 million, respectively for the three month and six month periods ended June 30, 2002, with no benefit for 2003.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion is intended to assist in an understanding of our historical financial position and results of operations for the three months and the six months ended June 30, 2003 and 2002. Please refer to our consolidated financial statements and notes thereto included elsewhere in this report for more detailed information in conjunction with the following discussion.

GENERAL

We are an independent natural gas and oil company engaged in the exploration, development, exploitation and acquisition of domestic natural gas and oil properties. Our operations are primarily focused in South Texas, offshore in the shallow waters of the Gulf of Mexico and in the Arkoma Basin of Oklahoma and Arkansas with additional production located in East Texas, South Louisiana and West Virginia.

At December 31, 2002, our net proved reserves were 650 billion cubic feet equivalent, or Bcfe, with a present value, discounted at 10% per annum, of cash flows before income taxes of $1.3 billion. Our reserves are fully engineered on an annual basis by independent petroleum engineers. Our focus is natural gas. Approximately 94% of our net proved reserves at December 31, 2002 were natural gas, approximately 69% of which were classified as proved developed. We operate approximately 85% of our properties.

We began exploring for natural gas and oil in December 1985 on behalf of The Brooklyn Union Gas Company. Brooklyn Union is an indirect wholly owned subsidiary of KeySpan Corporation. KeySpan, a member of the Standard & Poor's 500 Index, is a diversified energy provider whose principle 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 34% of our shares to the public, with KeySpan retaining the balance. As of June 30, 2003, THEC Holdings Corp., an indirect wholly owned subsidiary of KeySpan, owned approximately 56% of the outstanding shares of our common stock.

As an independent oil and gas producer, our revenue, profitability and future rate of growth are substantially dependent upon prevailing prices for natural gas and oil, our ability to find and produce natural gas and oil and our ability to control and reduce costs, all of which are dependent upon numerous factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. The energy markets have historically been very volatile and commodity prices may fluctuate widely in the future. A substantial or extended decline in natural gas and oil prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of natural gas and oil reserves that may be economically produced and access to capital.

Critical Accounting Policies and Use of Estimates

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.

Derivative Instruments. Our hedges are designated cash flow hedges and qualify for hedge accounting under Statement of Financial Accounting Standards ("SFAS") No. 133, as amended, "Accounting for Derivative Instruments and Hedging Activities" 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 ineffectiveness occurs, amounts are recorded directly to other income or expense.

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; plus,
- estimates for future development costs; 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 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 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, held constant over the life of the reserves. We use derivative financial instruments that qualify for hedge accounting under SFAS No. 133 to hedge against the volatility of natural gas prices, and in accordance with current Securities and Exchange Commission guidelines, we include estimated future cash flows from our hedging program in our ceiling test calculation. In calculating our ceiling test at June 30, 2003 and December 31, 2002, we estimated that we had a full cost ceiling "cushion", whereby the carrying value of our full cost pool was less than the ceiling limitation. No writedown is required when a cushion exists. Natural gas prices continue to be volatile and the risk that we will be required to write down our full cost pool increases when natural gas prices are depressed or if we have significant downward revisions in our estimated proved reserves.

Use of Estimates. The preparation of the consolidated financial statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires our 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 and our full cost ceiling limitation.

Natural gas and oil reserve quantities represent estimates only. Under full cost accounting, we use reserve estimates to determine our full cost ceiling limitation as well as our depletion rate. We estimate our proved reserves and future net revenues using sales prices estimated to be in effect as of the date we make the reserve estimates. We hold the estimates constant throughout the life of the properties, except to the extent a contract specifically provides for escalation. Natural gas prices, which have fluctuated widely in recent years, affect estimated quantities of proved reserves and future net revenues. Further, any estimates of natural gas and oil reserves and their values are inherently uncertain for numerous reasons, including many factors beyond our control. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. In addition, estimates of reserves may be revised based upon actual production, results of future development and exploration activities, prevailing natural gas and oil prices, operating costs and other factors, and these revisions may be material. Reserve estimates are highly dependent upon the accuracy of the underlying assumptions. Actual future production may be materially different from estimated reserve quantities and the differences could materially affect future amortization of natural gas and oil properties.

Accounting for Stock Option Expense

On January 1, 2003, we adopted the fair value expense recognition provisions of SFAS No. 123 "Accounting for Stock-Based Compensation" and as amended by SFAS No. 148, "Accounting for Stock-Based Compensation - Transition and Disclosure." Under the fair value method, compensation expense for stock options is recognized when stock options are issued. SFAS No. 148 proposes three alternative transition methods for a voluntary change to the fair value method under SFAS No. 123. We adopted SFAS No. 123 using the Prospective Method as defined by SFAS No. 148, and as a result, we now recognize as compensation expense the fair value of all stock options issued subsequent to December 31, 2002 with no expense recognized for options issued in previous periods. For the three months ended June 30, 2003, we recognized compensation expense of $44,000 for stock options granted during the period. For the corresponding six month period of 2003, we recognized $58,000 in compensation expense for stock options. Prior to our January 1, 2003 adoption of SFAS No. 123, we accounted for the incentive stock plans using the intrinsic value method prescribed under Accounting Principles Board Opinion No. 25, and accordingly, we did not recognize compensation expense for stock options granted.

Accounting for Asset Retirement Obligations

On January 1, 2003, we adopted SFAS No. 143, "Accounting for Asset Retirement Obligations," which addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. For us, asset retirement obligations represent the systematic, monthly accretion and depreciation of future abandonment costs of tangible assets such as platforms, wells, service assets, pipelines, and other facilities. SFAS No. 143 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, a gain or loss is recognized. Under our previous accounting method, we included estimated future costs of abandonment and dismantlement in our full cost amortization base and amortized these costs as a component of our depletion expense.

Pursuant to the January 1, 2003 adoption of SFAS No. 143 we:

- recognized a charge to income during the first quarter of 2003 of $2.8 million, net of tax, for the cumulative effect of the change in accounting principle;

- increased our total liabilities by $57.2 million to record the asset retirement obligations ("ARO");

- increased our assets by $42.5 million to add the asset retirement costs to the carrying amount of our natural gas and oil properties; and

- reduced our accumulated depreciation, depletion and amortization by $10.4 million for the amount of expense previously recognized.

Adopting SFAS No. 143 had no impact on our reported cash flows.

Recent Accounting Pronouncements

In April 2002 the Financial Accounting Standards Board ("FASB") issued SFAS No. 145, "Rescission of FASB Statements No. 4, No. 44, and No. 64, Amendment to FASB Statement No. 13 and Technical Corrections." SFAS No. 145 streamlines the reporting of debt extinguishments and requires that only gains and losses from extinguishments meeting the criteria in Accounting Policies Board Opinion No. 30 would be classified as extraordinary. Thus, gains or losses arising from extinguishments that are part of a company's recurring operations would not be reported as an extraordinary item. SFAS No. 145 is effective for fiscal years beginning after May 15, 2002. Our adoption of SFAS No. 145 on January 1, 2003 had no effect on our financial statements.

In June 2002, FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities" which addresses accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force ("EITF") Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." SFAS No. 146 requires that a liability for a cost associated with an exit or disposal activity be recognized when the liability is incurred. Under Issue 94-3, a liability for an exit cost was recognized at the date of an entity's commitment to an exit plan. Under SFAS No 146, fair value is the objective for initial measurement of the liability. SFAS No. 146 is effective for exit or disposal activities that are initiated after December 31, 2002. Our adoption of SFAS No. 146 on January 1, 2003 had no effect on our financial statements.

In November 2002, FASB issued Financial Interpretation ("FIN") No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." FIN 45 requires certain guarantees to be recorded at fair value, which is different from the current practice of recording a liability only when a loss is probable and reasonably estimable, as those terms are defined in SFAS No. 5, "Accounting for Contingencies." FIN 45 has a dual effective date. The initial recognition and measurement provisions are applicable on a prospective basis to guarantees issued or modified after December 31, 2002. The disclosure requirements in the interpretation are effective for financial statements for interim or annual periods ending after December 15, 2002. As of our December 31, 2002 and March 31, 2003 balance sheet dates, we did not have any guarantees of indebtedness of others and as a result, our adoption of FIN 45 did not have an effect on our financial statements.

On April 30, 2003, FASB issued SFAS 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities," which amends and clarifies accounting for derivative instruments, including certain derivative instruments embedded in other contracts, and hedging activities under SFAS No. 133. The new guidance amends SFAS 133 for decisions made:

- As a part of the Derivatives Implementation Group process that effectively required amendments to SFAS 133;

- In connection with other FASB projects dealing with financial instruments; and

- Regarding implementation issues raised in relation to the application of the definition of a derivative, particularly regarding the meaning of an "underlying" and the characteristics of a derivative that contains financing components.

The amendments set forth in SFAS 149 are intended to improve financial reporting by requiring that contracts with comparable characteristics be accounted for similarly. In particular, SFAS 149 clarifies the circumstances under which a contract with an initial net investment meets the characteristics of a derivative as discussed in SFAS 133. In addition, SFAS 149 clarifies when a derivative contains a financing component that warrants special reporting is the statement of cash flows. SFAS 149 amends certain other existing pronouncements, resulting in more consistent reporting of contracts that are derivatives in their entirely or that contain embedded derivatives that warrant separate accounting.

SFAS 149 is effective for contracts entered into or modified after June 30, 2003, except as stated below, and for hedging relationships designated after June 30, 2003. The guidance should be applied prospectively.

The provisions of SFAS 149 that relate to SFAS 133 Implementation Issues that have been effective for fiscal quarters that began prior to June 15, 2003 should continue to be applied in accordance with their respective effective dates. In addition, certain provisions relating to forward purchases or sales of "when issued" securities or other securities that do not yet exist should be applied to existing contracts as well as new contracts entered into after June 30, 2003. Our adoption of SFAS 149 will not have an effect on our financial statements.

On May 15, 2003, FASB issued SFAS 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity," which aims to eliminate diversity in practice by requiring that the following three types of "freestanding" financial instruments be reported as liabilities by their issuers:

- Mandatorily redeemable instruments (i.e., instruments issued in the form of shares that unconditionally obligate the issuer to redeem the shares for cash or by transferring other assets);

- Forward purchase contract, written put options, and other financial instruments not in the form of shares that either obligate or may obligate the issuer to repurchase its equity shares and settle its obligation for cash or by transferring other assets; and,

- Certain financial instruments that include an obligation that (1) the issuer may or must settle by issuing a variable number of its equity shares and (2) has a "monetary value" at inception that (a) is fixed, (b) is tied to a market index or other benchmark (something other than the fair value of the issuer's equity shares), or (c) varies inversely with the fair value of the equity shares (e.g., a written put option).

Until this pronouncement was issued, these types of instruments have been variously presented by their issuers as liabilities, as part of equity, or between the liabilities and equity sections (sometimes referred to as "mezzanine" reporting) in the statement of financial position.

For our company, the provisions of SFAS 150, which also include a number of new disclosure requirements, are effective for (1) instruments interest into or modified after May 31, 2003 and (2) pre-existing instruments as of the beginning of the first interim period that commences after June 15, 2003. Our adoption of SFAS 150 has had no effect on our financial statements.

RECENT DEVELOPMENTS

Increase in Capital Expenditure Budget for 2003

At the quarterly meeting of our Board of Directors held July 29, 2003, our 2003 capital expenditure budget was increased by $26 million to $312 million. We plan to spend two-thirds of the increase in South Texas and the balance in the Arkoma Basin.

Stephen W. McKessy Elected Director

Stephen W. McKessy was elected to our Board of Directors at the quarterly meeting held July 29, 2003. Upon Mr. McKessy's election to the Board, the size of our Board was increased from 10 to 11 members. Mr. McKessy is a retired Vice Chairman of PricewaterhouseCoopers where he worked from 1960 to 1997. During his 37 years with the firm he held various management positions, including serving as a member of the firm's management committee. He was also the regional managing partner for the firm's businesses in the New York area. A graduate of St. John's University in New York, McKessy currently serves on the advisory board for the college of business administration. Mr. McKessy is a board member of KeySpan Energy Corporation.

Rocky Mountain Exploration

During the first half 2003, we acquired approximately 85,000 net undeveloped acres in located onshore in Rocky Mountain region of the northwestern Untied States. The acreage is located in southwestern Montana, the Green River Basin of southwestern Wyoming and in the Uinta Basin of northeast Utah. In April 2003, we opened an office in Denver, Colorado that is currently staffed by one geo-scientist to coordinate prospect flow. We are planning to drill 3 to 5 wells during the fourth quarter of 2003. The wells planned will be less than 5,000 feet in depth. As June 30, 2003, we incurred approximately $3.4 million in leasehold acquisition costs related to the acreage acquired.

Issuance of $175 Million 7% Notes due 2013 and Redemption of $100 Million 8 5/8% Notes due 2008

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. 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. 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 which 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 of the notes 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.

We received $170.9 million in net proceeds from the issuance of the notes. A portion of the net proceeds was used to repay the aggregate principal of $100 million on the 8 5/8% senior subordinated notes together with a premium of $4.3 million for early redemption. The remaining portion of the net proceeds was used to repay $60 million in outstanding borrowings on our revolving bank credit facility with the balance of approximately $6.6 million being applied to working capital, a portion of which was utilized in July to fund the payment of $4.6 million in accrued interest due on the notes. At June 30, 2003 and pursuant to the early redemption of the $100 million notes, we incurred debt extinguishment expenses totaling $5.9 million ($3.9 million net of tax) for the call premium of $4.3 million together with a non-cash charge of $1.6 million for the write-off of the balance of the unamortized issue costs. The debt extinguishment expenses of $5.9 million are included in the line item "Other (Income) Expense on the Statement of Operations for the three and the six months ended June 30, 2003.

Pursuant to a registration rights agreement relating to the 7% senior subordinated notes among us and the initial purchasers, we have agreed to file a registration statement with the SEC for the offer to exchange the notes for new notes registered under the Securities Act which will have terms identical in all material respects to the existing notes.

Issuance of 3,000,000 Shares to the Public and Concurrent Repurchase of 3,000,000 Shares from KeySpan

In connection with our initial public offering in September 1996, we entered into a registration rights agreement with KeySpan pursuant to which we are obligated, at KeySpan's election, to facilitate KeySpan's sale of its shares of Company stock by registering the shares under the Securities Act of 1933 and assisting in KeySpan's selling efforts. During February of 2003, KeySpan notified us of its desire to sell 3,000,000 shares of their Company stock. For the mutual convenience of the parties, we elected to effect KeySpan's sale through our pre-existing registration statement rather than filing a separate, new registration statement for KeySpan. To accomplish the transaction, we simultaneously sold 3,000,000 newly issued shares of Company stock in a public offering for net proceeds of $26.40 per share, or an aggregate $79.2 million, and bought a like number of KeySpan's shares of Company stock for the same price per share. We cancelled the 3,000,000 shares acquired from KeySpan immediately following the repurchase. KeySpan reimbursed us for all costs and expenses, and the transaction had no impact on our capitalization. The transaction was evidenced in a stock purchase agreement, dated February 26, 2003. Our Board of Directors approved the transaction in principle and delegated to a special, independent committee of the Board plenary authority to negotiate the terms of, and finally approve or veto, the transaction. In finally approving the terms of the stock purchase agreement, the independent committee determined that the agreement was consistent with our pre-existing obligations under our registration rights agreement and that issuing the shares under our existing registration statement was in the best interests of our public stockholders to facilitate the prompt and orderly disposition of the shares. As a result of the transactions, KeySpan's interest in our outstanding shares decreased from 66% to 56%.

As KeySpan has announced in the past, it does not consider certain businesses contained in its energy investments segment, including its investment in Houston Exploration, a part of its core asset group. KeySpan has stated in the past that it may sell or otherwise dispose of all or a portion of its non-core assets, including all or a portion of its common stock ownership in our company. As stated above, on February 20, 2003 KeySpan sold to us 3,000,000 shares of our common stock it owned, reducing its ownership percentage from approximately 66% to 56%. KeySpan has stated that based on market conditions, it cannot predict when, or if, any additional sales or dispositions of all or a part of its remaining ownership interest in us may take place.

RESULTS OF OPERATIONS

The following table sets forth our historical natural gas and oil production data during the periods indicated:

	THREE MONTHS ENDED JUNE 30, 2003	THREE MONTHS ENDED JUNE 30, 2002	2
PRODUCTION:			
Natural gas (MMcf)	24,634	24,450	
Oil (MBbls)	328	222	
Total (MMcfe)	26,602	25,782	
Average daily production (MMcfe/day)	292	283	
AVERAGE SALES PRICES:			
Natural gas (per Mcf) realized(1)	$ 4.54	$ 3.28	$
Natural gas (per Mcf) unhedged	5.16	3.28	
Oil (per Bbl) realized(1)	26.18	24.04	
Oil (per Bbl) unhedged	25.95	24.04	
OPERATING EXPENSES (PER MCFE):			
Lease operating	$ 0.44	$ 0.31	$
Severance tax	0.12	0.11	
Transportation expense	0.10	0.09	
Depreciation, depletion and amortization	1.79	1.63	
Asset retirement accretion	0.03	--	
General and administrative, net	0.16	0.10	

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(1) Reflects the effects of hedging.

RECENT FINANCIAL AND OPERATING RESULTS

Comparison of Three Months Ended June 30, 2003 and 2002

Production. Our production increased 3% from 25,782 million cubic feet equivalent, or MMcfe, for the three months ended June 30, 2002 to 26,602 MMcfe for the three months ended June 30, 2003. Average daily production was 292 MMcfe/day during the second quarter of 2003 compared to 283 MMcfe/day during the second quarter of 2002.

Onshore, our daily production rates increased 15% from an average of 149 MMcfe/day during the second quarter of 2002 to an average of 171 MMcfe/day during the corresponding three months of 2003. The increase in onshore production is primarily attributable to 23 MMcfe/day in newly developed production in South Texas. Production from our other onshore areas remained relatively unchanged at 32 MMcfe/day during the second quarter of 2003 compared to 33 MMcfe/day during the second quarter of 2002. In total, average daily production during the second quarter of 2003 decreased slightly to 171 MMcfe/day as compared to production during the first quarter of 2003 of 173 MMcfe/day.

Offshore, our production decreased 10% from an average of 134 MMcfe/day during the second quarter of 2002 to an average of 121 MMcfe/day during the second quarter of 2003. Production declines due to maturing reservoirs from existing key fields, Mustang Island A-31/32, West Cameron 587, South Marsh Island 253 and North Padre Island 883, were greater than incremental production added from new wells and facilities brought on-line since the end of the second quarter of 2002 at Vermilion 408, East Cameron 81/84, East Cameron 82/83, Mustang Island 785 and South Timbalier 314/317. The year-over-year production decline is partially the result of shifting approximately $40 million of our 2002 offshore capital expenditure program to our onshore region to facilitate the May 2002 acquisition of producing properties in South Texas from Burlington Resources. However, during the second quarter of 2003 offshore production increased by 5% to 121 MMcfe/day from 115 MMcfe/day during the first quarter of 2003. The increase was due in part to an increase in production at South Timbalier 314/317, a successful recompletion at High Island 38 completed in the first quarter of 2003

and the resolution of downstream pipeline problems during January and February at Vermilion 408.

Natural Gas and Oil Revenues. Natural gas and oil revenues increased 41% from $85.6 million for the second quarter of 2002 to $120.4 million for the second quarter of 2003 as a result of a 38% increase in average realized natural gas prices, from $3.28 per Mcf during the second quarter of 2002 to $4.54 per Mcf in the second quarter of 2003 and an increase in average realized oil prices of 9% for the same period from $24.04 per barrel, or Bbl, to $26.18 per barrel, combined with a 48% increase in production during the current quarter.

Natural Gas Prices. As a result of hedging activities during the second quarter of 2003, we realized an average gas price of $4.54 per Mcf, which was 88% of the average unhedged natural gas price of $5.16 for the period. As a result, natural gas and oil revenues for the three months ended June 30, 2003 were $15.4 million lower than the revenues we would have achieved if hedges had not been in place during the period. For the corresponding quarter of 2002, our hedging activities resulted in $12,000 of additional natural gas revenues, and, as a result, our average realized natural gas price and unhedged natural gas price were equal at $3.28 per Mcf.

Oil Prices. During the second quarter of 2003, we realized an average oil price of $26.18 per Bbl, which was 101% of the average unhedged price of $25.95 per Bbl for the period. As a result, natural gas and oil revenues for the three months ended June 30, 2003 were $73,000 higher than the revenues we would have achieved if hedges had not been in place during the period. We had no oil hedges in place during second quarter of 2002 and realized an average oil price of $24.04 per Bbl.

Lease Operating Expenses and Severance Tax. Lease operating expenses increased 48% from $7.9 million for the three months ended June 30, 2002 to $11.7 million for the corresponding three months of 2003. On an Mcfe basis, lease operating expenses increased 42% from $0.31 per Mcfe during the second quarter of 2002 to $0.44 per Mcfe during the second quarter of 2003. The increase in both lease operating expenses and lease operating expense on a per unit basis for 2003 is primarily attributable to the continued expansion of our operations both onshore and offshore. Our overall operating expenses are increasing as we add new wells and facilities and continue to maintain production from existing properties. Since the end of the second quarter of 2002, we added approximately 100 new wells from exploration and development drilling. Specifically, ad valorem taxes increased as onshore property values are higher than prior year as a result of higher commodity prices. South Timbalier 314/317 was placed on-line during the first quarter of 2003 and is inherently more costly to operate, as it is a crude oil producing property. We are incurring additional fees to process natural gas from new wells at East Cameron 81/83/84. And finally, we have added compression in South Texas and at several offshore platforms to enhance production capabilities from existing wells.

Severance tax, which is a function of volume and revenues generated from onshore production, increased from $2.8 million for the second quarter of 2002 to $3.2 million for the corresponding period of 2003. On an Mcfe basis, severance tax increased 9% from $0.11 per Mcfe during the second quarter of 2002 to $0.12 per Mcfe during the second quarter of 2003. Despite our reduced severance tax rate for a portion of our South Texas production pursuant to the "high-cost/tight-gas formation" designation received in July 2002 (see "Other (Income) and Expense" below), severance tax expense and severance tax per Mcfe increased during the second quarter of 2003 due to the 57% increase in average wellhead prices for natural gas from $3.28/Mcf during the second quarter of 2002 to $5.16/Mcf during the second quarter of 2003 combined with a 14% increase in onshore production for the same period of 2003.

Transportation Expense. We applied EITF No. 00-10 "Accounting for Shipping and Handling Fees and Costs" for all periods presented. Pursuant to our application of EITF No. 00-10, transportation expenses for the three months ended June 30, 2002 that were previously reflected as a reduction of natural gas and oil revenues were added back to the related revenues and reclassified as a separate component of operating expense. The application of EITF No. 00-10 had no effect on operating income or net income. Transportation expense for the second quarter of 2003 increased 11% on an Mcfe basis from $0.09 during the second quarter of 2002 to $0.10 for the second quarter of 2003. The increase reflects an increase in volume, primarily in South Texas, that is subject to transportation fee agreements the current quarter.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased 14% from $42.0 million for the three months ended June 30, 2002 to $47.7 million for the three months ended June 30, 2003. Depreciation, depletion and amortization expense per Mcfe increased 10% from $1.63 for the three months ended June 30, 2002 to $1.79 for the corresponding three months in 2003. The increase in depreciation, depletion and amortization expense was a result of higher production volumes combined with a higher depletion rate. Our depletion rate has increased as the costs associated with several unproved properties designated as unevaluated were reclassified into our amortization base

without incremental reserve additions at the end of 2002. In addition, our estimated future development costs at December 31, 2002, increased approximately 22% from prior year estimates due to the addition of more proved undeveloped reserves into our total proved reserve base.

Asset Retirement Accretion. Pursuant to our January 1, 2003 adoption of SFAS No. 143, "Asset Retirement Obligations," we incurred asset retirement accretion expense of $0.8 million, $0.03 per Mcfe, during the second quarter of 2003. The accretion expense represents the systematic, monthly accretion and depreciation of future abandonment costs of tangible assets such as platforms, wells, service assets, pipelines, and other facilities.

General and Administrative Expenses, Net of Capitalized General and Administrative and Overhead Reimbursements. Our net general and administrative expenses increased 68% from $2.5 million for the three months ended June 30, 2002 to $4.2 million for the three months ended June 30, 2003. These amounts are net of overhead reimbursements received from other working interest owners of $0.3 million and $0.4 million for the three months ended June 30, 2002 and 2003, respectively, and capitalized general and administrative expenses of $3.1 million and $2.9 million for the respective periods. Aggregate general and administrative expenses increased by $1.6 million or 27% from $5.9 million during the second quarter of 2002 to $7.5 million for the second quarter of 2003. The increase in aggregate general and administrative expense is due primarily to the expansion of our workforce which corresponds to the continued expansion of our operations. As our workforce expands, we have experienced an increase in salaries and related employee benefit expenses together with an increase in our incentive compensation expense. In addition, our rent expense has increased as we expanded our leased office space in downtown Houston to accommodate our growing workforce. Finally, our legal, audit and accounting expenses increased as we implemented new corporate governance policies and engaged an outside firm to perform internal auditing functions.

On an Mcfe basis, net general and administrative expenses increased 60% from $0.10 during the second quarter of 2002 to $0.16 per Mcfe during the second quarter of 2003. The higher rate per Mcfe during the second quarter of 2003 reflects the increase in our aggregate general and administrative expenses offset in part by a 6% decrease in capitalized expenses during the second quarter of 2003 which is a result of a change in the mix of types of general and administrative expenses we are incurring. We are incurring more expenses that are not directly related to our oil and gas exploration and development operations.

Other Income and Expense. For the second quarter of 2003, Other Income and Expense includes two components: (i) debt extinguishment expenses totaling $5.9 million ($3.9 million net of tax); and (ii) income of $2.3 million ($1.5 million net of tax) related to refunds of prior year's severance tax expense. Upon completion of the private placement of our $175 million 7% senior subordinated notes due June 2013 on June 10, 2003, we called our $100 million 8 5/8% senior subordinated notes due 2008 for redemption. We incurred a premium for early redemption of the $100 million 8 5/8% notes of $4.3 million together with a non-cash charge of $1.6 million to write-off the balance of the unamortized costs associated with issuing the $100 million notes.

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. The "high-cost/tight-gas formation" designation allows us to receive an abatement of severance taxes for qualifying wells in various fields. For qualifying wells, production will be either exempt from tax or taxed at a reduced rate until certain capital costs are recovered. For qualifying wells, we will also be entitled to a refund of severance taxes paid during a designated prior 48-month period. Applications for refund are submitted on a well-by-well basis to the State Comptroller's Office and due to timing of the acceptance of applications, we are unable to project the 48-month look-back period for qualifying refunds. As of the date of our report, we are estimating that we could receive refunds of up to an additional $1.2 million ($0.8 million net of tax), although there can be no assurances that actual amounts collected will equal our estimates.

Interest Expense, Net of Capitalized Interest. Interest expense, net of capitalized interest, increased 38% from $1.6 million during the second quarter of 2002 to $2.2 million during the second quarter of 2003. Aggregate interest expense increased from $3.6 million during the second quarter of 2002 to $4.0 million during the second quarter of 2003. Our average borrowings and interest rates were $229.5 million and 6.43% during the second quarter of 2003 compared to $261.1 million and 5.28% during the second quarter of 2002. For the current quarter, our average borrowings decreased and our average interest rate increased as we replaced our existing fixed debt of $100 million at 8 5/8% with new fixed debt of $175 million at 7% and used excess proceeds from the newly issued debt to repay outstanding borrowings under our revolving bank credit facility which bears interest at lower rates that averaged 3.3% during both the second quarter of 2003 and 2002. In addition, the increase in net interest expense for the second quarter of 2003 reflects a decrease in capitalized

interest. Capitalized interest decreased 10% from $2.0 million during the second quarter of 2002 to $1.8 million during the second quarter of 2003 and is a result of a decrease in our unevaluated property balance from $139.1 million at June 30,, 2002 to $102.2 million at June 30, 2003. Our capitalized interest, which is a function of unevaluated properties, decreased during the quarter corresponding to a decrease in our unevaluated property balance as several properties previously designated as unevaluated were reclassified to the amortization base or full cost pool at the end of 2002.

Income Tax Provision. The provision for income taxes increased 70% from $9.2 million for the second quarter of 2002 to $15.6 million for the second quarter of 2003 due to the 65% increase in pre-tax income during the second quarter of 2003 from $26.9 million during the second quarter of 2002 to $44.5 million during the second quarter of 2003. Pre-tax income is higher as a result of the 41% increase in revenues and $2.3 million in other income as a result of refunds of prior period severance tax offset in part by a 22% increase in operating expenses, a 38% increase in net interest expense and $5.9 million in debt extinguishment expenses.

Operating Income and Income before Cumulative Effect of Change in Accounting Principle. For the three months ended June 30, 2003, the 38% increase in realized natural gas prices combined with the 3% increase in production, offset in part by a 22% increase in operating expenses, caused operating income to increase 76% from $28.5 million during the second quarter of 2002 to $50.3 million during the second quarter of 2003. Correspondingly, income before the cumulative effect of the change in accounting principle increased 63% from $17.7 million for the second quarter of 2002 to $28.9 million for the second quarter of 2003.

Comparison of Six Months Ended June 30, 2003 and 2002

Production. Our production increased 4% from 50,637 million cubic feet equivalent, or MMcfe, for the six months ended June 30, 2002 to 52,529 MMcfe for the six months ended June 30, 2003. Average daily production was 290 MMcfe/day during the first half of 2003 compared to 280 MMcfe/day during the first half of 2002.

Onshore, our daily production rates increased 18% from an average of 146 MMcfe/day during the first half of 2002 to an average of 172 MMcfe/day during the corresponding six months of 2003. The increase in onshore production is primarily attributable to 28 MMcfe/day in newly developed production from in South Texas. Production from our other onshore areas declined slightly by 2 MMcfe/day from 34 MMcfe/day during the first half of 2002 to 32 MMcfe/day during the first half of 2003.

Offshore, our production decreased 12% from an average of 134 MMcfe/day during the first half of 2002 to an average of 118 MMcfe/day during the first half of 2003. Production declines due to maturing reservoirs from existing key fields, Mustang Island A-31/32, High Island 39, West Cameron 587 and South Marsh Island 253, were greater than incremental production added from new wells and facilities brought on-line since the end of the first half of 2002 at Vermilion 408, East Cameron 81/84, East Cameron 82/83, Mustang Island 785, High Island 38, and South Timbalier 314/317. Further, we experienced a loss of an estimated 3

MMcfe/day at Vermilion 408 during a 15 day shut-in during January and February 2003 due to down stream pipeline shut-ins for repairs. The year-over-year production decline is partially the result of shifting approximately $40 million of our 2002 offshore capital expenditure program to our onshore region to facilitate the May 2002 acquisition of producing properties in South Texas from Burlington Resources.

Natural Gas and Oil Revenues. Natural gas and oil revenues increased 56% from $160.0 million during the first six months of 2002 to $248.8 million during the first six months of 2003 as a result of a 51% increase in average realized natural gas prices, from $3.14 per Mcf during the first half of 2002 to $4.73 per Mcf in the first half of 2003 and an increase in average realized oil prices of 29% for the same period from $22.05 per barrel, or Bbl, to $28.55 per barrel, combined with a 53% increase in oil production during the current quarter.

Natural Gas Prices. As a result of hedging activities during the first half of 2003, we realized an average gas price of $4.73 per Mcf, which was 82% of the average unhedged natural gas price of $5.76 for the period. As a result, natural gas and oil revenues for the six months ended June 30, 2003 that were $50.0 million lower than the revenues we would have achieved if hedges had not been in place during the period. For the corresponding six months of 2002, we realized an average gas price of $3.14 per Mcf, which was 113% of the average unhedged natural gas price of $2.79 for the period. This resulted in natural gas and oil revenues that were $17.0 million higher than the revenues we would have achieved if hedges had not been in place during the period.

Oil Prices. During the first half of 2003, we realized an average oil price of $28.55 per Bbl, which was 98% of the average unhedged price of $29.24 per Bbl for the period. As a result, natural gas and oil revenues for the six months ended June 30, 2003 were $0.4 million lower than the revenues we would have achieved if hedges had not been in place during the period. We had no oil hedges in place during first half of 2002 and realized an average oil price of $22.05 per Bbl.

Lease Operating Expenses and Severance Tax. Lease operating expenses increased 52% from $15.3 million for the six months ended June 30, 2002 to $23.3 million for the corresponding six months of 2003. On an Mcfe basis, lease operating expenses increased 47% from $0.30 per Mcfe during the first half of 2002 to $0.44 per Mcfe during the first half of 2003. The increase in both lease operating expenses and lease operating expense on a per unit basis for 2003 is attributable to the continued expansion of our operations both onshore and offshore. Our overall operating expenses are increasing as we add new wells and facilities and continue to maintain production from existing properties. Since the end of the second quarter of 2002, we added approximately 100 new wells from exploration and development drilling. Onshore, ad valorem taxes, compression costs, well control insurance and contract service expenses have increased in the current period. In addition, during the first quarter of 2003, we incurred $1.6 million in non-recurring expenses associated with a workover in the Charco Field. Offshore, we added new crude oil production facilities at South Timbalier 314/317 during the first quarter of 2003 and since the end of the second quarter of 2002, we added new wells and facilities at East Cameron 81/83/84 which are incurring incremental fees to process the natural gas. In addition, we installed compressors at several platforms to enhance production capabilities from existing wells.

Severance tax, which is a function of volume and revenues generated from onshore production, increased from $4.5 million for the first six months of

2002 to $7.5 million for the corresponding period of 2003. On an Mcfe basis, severance tax increased from $0.09 per Mcfe for the first half of 2002 to $0.14 per Mcfe during the first half of 2003. Despite our reduced severance tax rate for a portion of our South Texas production pursuant to the "high-cost/tight-gas formation" designation received in July 2002 (see "Other (Income) and Expense" below), severance tax expense and severance tax per Mcfe increased during the first six months of 2003 due to the 106% increase in average wellhead prices for natural gas from $2.79 during the first half of 2002 to $5.76 during the first half of 2003 combined with a 18% increase in onshore production for the first half of 2003.

Transportation Expense. We applied EITF No. 00-10 "Accounting for Shipping and Handling Fees and Costs" for all periods presented. Pursuant to our application of EITF No. 00-10, transportation expenses for the six months ended June 30, 2002 that were previously reflected as a reduction of natural gas and oil revenues were added back to the related revenues and reclassified as a separate component of operating expense. The application of EITF No. 00-10 had no effect on operating income or net income. Transportation expense increased 11% on an Mcfe basis from $0.09 during the first six months of 2002 to $0.10 for the first six months of 2003. The increase reflects an increase in volume, primarily in South Texas, that is subject to transportation fee agreements during 2003.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased 14% from $81.8 million for the six months ended June 30, 2002 to $93.4 million for the six months ended June 30, 2003. Depreciation, depletion and amortization expense per Mcfe increased 10% from $1.62 for the six months ended June 30, 2002 to $1.78 for the corresponding six months in 2003. The increase in depreciation, depletion and amortization expense was a result of higher production volumes combined with a higher depletion rate. Our depletion rate has increased as the costs associated with several unproved properties designated as unevaluated were reclassified into our amortization base without incremental reserve additions at the end of 2002. In addition, our estimated future development costs increased approximately 22% at December 31, 2002 from prior year estimates due to the addition of more proved undeveloped reserves into our total proved reserve base.

Asset Retirement Accretion. Pursuant to our January 1, 2003 adoption of SFAS No. 143, "Asset Retirement Obligations," we incurred asset retirement accretion expense of $1.6 million, $0.03 per Mcfe, for the first six months of 2003. The accretion expense represents the systematic, monthly accretion and depreciation of future abandonment costs of tangible assets such as platforms, wells, service assets, pipelines, and other facilities.

General and Administrative Expenses, Net of Capitalized General and Administrative and Overhead Reimbursements. Our net general and administrative expenses increased 40% from $5.8 million for the six months ended June 30, 2002 to $8.1 million for the six months ended June 30, 2003. These amounts are net of overhead reimbursements received from other working interest owners of $0.9 million and $0.8 million for the six months ended June 30, 2002 and 2003, respectively, and capitalized general and administrative expenses of $6.4 million and $6.6 million for the respective periods. Aggregate general and administrative expenses increased by $2.4 million or 18% from $13.1 million for the first

half of 2002 to $15.5 million for the first half of 2003. However, included in aggregate expense for the first half of 2002 was approximately $0.9 million in non-recurring charges relating to employee severance payments. Without these non-recurring charges, aggregate general and administrative expense for the first half of 2003 would reflect a $3.3 million or 27% increase from the first half of 2002 and net general and administrative expenses for the first half of 2003 would reflect a $3.2 million or 65% increase. The increase in aggregate general and administrative expense is due primarily to the expansion of our workforce which corresponds to the continued expansion of our operations. As our workforce expands, we have experienced an increase in salaries and related employee benefit expenses together with an increase in our incentive compensation expense. In addition, our rent expense has increased as we expanded our leased office space in downtown Houston to accommodate our growing workforce. Finally, our legal, audit and accounting expenses increased as we implemented new corporate governance policies and engaged an outside firm to perform internal auditing functions.

On an Mcfe basis, net general and administrative expenses increased 25% from $0.12 during the first half of 2002 to $0.15 per Mcfe during the first half of 2003. Without the non-recurring charges of $0.9 million incurred in the first half of 2002 for employee severance payments, net general and administrative expense per Mcfe would have increased by $0.05 per Mcfe or by 50% from $0.10 in first half 2002 to $0.15 in the first half of 2003. The higher rate per Mcfe during the first half of 2003 reflects the increase in our aggregate general and administrative expenses.

Other Income and Expense. For the first half of 2003, Other Income and Expense includes two components: (i) debt extinguishment expenses totaling $5.9 million ($3.9 million net of tax); and (ii) income of $12.9 million ($8.4 million net of tax) related to refunds of prior year's severance tax expense. Upon completing the private placement of our $175 million 7% senior subordinated notes June due 2013 on June 10, 2003, we called our $100 million 8 5/8% senior subordinated notes due 2008 for redemption. We incurred a premium for early redemption of the $100 million 8 5/8% notes of $4.3 million together with a non-cash charge of $1.6 million to write-off the balance of the unamortized costs associated with issuing the $100 million notes.

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. The "high-cost/tight-gas formation" designation allows us to receive an abatement of severance taxes for qualifying wells in various fields. For qualifying wells, production will be either exempt from tax or taxed at a reduced rate until certain capital costs are recovered. For qualifying wells, we will also be entitled to a refund of severance taxes paid during a designated prior 48-month period. Applications for refund are submitted on a well-by-well basis to the State Comptroller's Office and due to timing of the acceptance of applications, we are unable to project the 48-month look-back period for qualifying refunds. As of the date of our report, we are estimating that we could receive refunds of up to an additional $1.2 million ($0.8 million net of tax), although there can be no assurances that actual amounts collected will equal our estimates.

Interest Expense, Net of Capitalized Interest. Interest expense, net of capitalized interest, increased 47% from $3.0 million for the first six months of 2002 to $4.4 million for the first six months of 2003. Aggregate interest expense increased 6% from $7.2 million during the first half of 2002 to $7.6 million during corresponding six months of 2003. Our average borrowings and interest rates were $255.8 million and 5.32% during the first half of 2002 compared to $239.8 million and 5.91% during the first half of 2003. The increase in net interest expense for the current period is due in part to the higher average rate combined with a decrease in capitalized interest. Capitalized interest decreased 24% from $4.2 million for the first half of 2002 to $3.2 million for the first half of 2003. Our capitalized interest is a function of unevaluated properties and the decrease corresponds to the decrease in our unevaluated property balance from $139.1 million at June 30, 2002 to $102.2

million at June 30, 2003. Unevaluated properties are lower in the current period as a result of several properties previously designated as unevaluated being reclassified to the amortization base or full cost pool at the end of 2002.

Income Tax Provision. The provision for income taxes increased 152% from $15.7 million for the first six months of 2002 to $39.6 million for the first six months of 2003 due to the 146% increase in pre-tax income during the first half of 2003 from $45.9 million during the first half of 2002 to $113.0 million during the first half of 2003. Pre-tax income is higher as a result of the 55% increase in revenues and the $7.0 million in other income that resulted from a combination of $12.9 million in severance refunds and $5.9 million in debt extinguishment expenses. The increase in revenues and other income was offset in part by a 24% increase in operating expenses and a 47% increase in net interest expense.

Operating Income and Income before Cumulative Effect of Change in Accounting Principle. For the six months ended June 30, 2003, the 51% increase in realized natural gas prices combined with the 4% increase in production, offset in part by a 24% increase in operating expenses, caused operating income to increase 126% from $48.9 million during the first half

of 2002 to $110.5 million during the first half of 2003. Correspondingly, income before the cumulative effect of the change in accounting principle increased 143% from $30.2 million for the first half of 2002 to $73.4 million for the first half of 2003.

LIQUIDITY AND CAPITAL RESOURCES

We fund our operations, including capital expenditures and working capital requirements, from cash flows from operations and bank borrowings. We believe cash flows from operations and borrowings under our revolving bank credit facility will be sufficient to fund our planned capital expenditures and operating expenses during 2003. In June 2003, we took advantage of lower interest rates and called our $100 million 8 5/8% senior subordinated notes due January 2008 for early redemption and issued $175 million 7% senior subordinated notes due June 2023. We received $170.9 million in net proceeds from the private placement of the $175 million 7% senior subordinated notes. Of the net proceeds received, we transferred $104.3 million directly to the trustee who placed the funds in a short-term investment vehicle for use in the July 11, 2003 repayment of the aggregate principal of $100 million on the 8 5/8% senior subordinated notes together with a premium of $4.3 million for early redemption of the notes. The remaining portion of the net proceeds was used to repay $60 million in outstanding borrowings on our revolving bank credit facility with the balance of approximately $6.6 million being applied to working capital, a portion of which was utilized in July 2003 to fund the payment to the trustee of $4.6 million in accrued interest due on the $100 million 8 5/8% notes.

Cash Flows. As of June 30, 2003, we had working capital deficit of $17.1 million and $260.6 million of borrowing capacity available under our revolving bank credit facility. Our working capital deficit is due to the fair value of a portion of our derivative financial instruments of $54.4 million that is classified as a current liability. Net cash provided by operating activities for the first six months of 2003 was $185.6 million compared to $108 million during the first six months of 2002. The 72% increase in net cash provided by operating activities was due to an increase in net income caused primarily by higher realized natural gas prices and an increase in production volumes for the half 2003 together with an increase in operating assets and current liabilities. For the first half of 2003, the increase in operating assets was caused primarily by an increase in receivables for natural gas revenues due to comparatively higher gas prices and production volumes together with our receivable at June 30, 2003 for severance tax refunds totaling $28.2 million. Current liabilities (excluding the fair value of derivatives which is a non-cash item) increased due to a higher level of drilling activity in the first half of 2003 as compared to the first half of 2002. For the first six months of 2003, funds used in investing activities consisted of $138.3 million for net cash investments in property and equipment, which compares to $130.9 million spent during the first six months of 2002. Proceeds from long-term borrowings increased our cash position during the first half of 2003 by a net $43 million. We issued $175 million in 7% senior subordinated notes and repaid a net $132 million in borrowings under our revolving bank credit facility. For the corresponding six months of 2002, net cash increased by $36 million from incremental borrowings under our revolving bank credit facility. During the current period, we incurred $4.1 million in costs related to the issuance of the new $175 million 7% senior subordinated notes. Cash increased by $2.5 million and $1.2 million, respectively, during the first half of 2003 and 2002 due to proceeds received from the issuance of common stock from the exercise of stock options. In addition, during the first quarter of 2003, we sold 3 million newly issued shares of our common stock in a public offering for net proceeds of $79.2 million, and simultaneously repurchased the same number of shares from KeySpan for $79.2 million. As a result of these operating, investing and financing activities, cash and cash equivalents increased $88.6 million from $18.0 million at December 31, 2002 to $106.6 million at June 30, 2003. The cash balance at June 30, 2003 includes a temporary cash investment of $104.3 million that was used on July 11, 2003 for the repayment of $100 million in aggregate principal together with a $4.3 million early redemption premium for the 8 5/8% senior subordinated notes.

Investments in Property and Equipment. During the half of 2003, we invested $137.7 million in natural gas and oil properties and $0.8 million for other property and office equipment. During the six months of 2003, we completed the drilling of 72 gross wells (55.9 net) of which 53 (41.7 net) were successful and 19 (14.2 net) were unsuccessful with an additional 14 wells (12 net) in progress at the end to the quarter. Our investments in natural gas and oil properties included $30.3 million in exploration costs, $79.2 million in development costs and $28.2 in leasehold acquisition costs. Leasehold acquisition costs include among other things, costs incurred for seismic, capitalized interest and capitalized general and administrative costs. During the six months of 2003 and 2002, we capitalized a total of $9.8 million and $10.6 million, respectively, in interest and general and administrative expenses.

Future Capital Requirements. At the quarterly meeting of our Board of Directors held July 29, 2003, our 2003 capital expenditure budget of $286 million was increased by $26 million to $312 million. We are planning to spend two-thirds of the increase in South Texas and the balance in the Arkoma Basin. As of June 30, 2003, we had spent approximately 48% of our initial capital expenditure budget of $286 million for 2003. We do not include property acquisition costs in our

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capital expenditure budget because the size and timing of capital requirements for acquisitions are inherently unpredictable. The capital expenditure budget includes exploration and development costs associated with projects in progress or planned for the upcoming year and amounts are contingent upon drilling success. We have estimated our current asset retirement obligations to be $4.5 million. No assurances can be made that amounts budgeted will equal actual amounts spent. We will continue to evaluate our capital spending plans throughout the year. Actual levels of capital expenditures may vary significantly due to a variety of factors, including drilling results, natural gas prices, industry conditions and outlook and future acquisitions of properties. We believe cash flows from operations and borrowings under our credit facility will be sufficient to fund these expenditures. We intend to continue to selectively seek acquisition opportunities both offshore and onshore although we may not be able to identify and make acquisitions of proved reserves on terms we consider favorable.

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 as documentation agent. The credit facility provides us with a commitment of $300 million which may be increased at our request and with prior approval from Wachovia to a maximum of $350 million by adding one or more lenders or by allowing one or more lenders to increase their commitments. The credit facility is subject to borrowing base limitations. Our current borrowing base is $300 million and is redetermined semi-annually, with the next redetermination scheduled for October 1, 2003. Up to $25 million of the borrowing base is available for the issuance of letters of credit. The credit facility matures July 15, 2005, is unsecured and with the exception of trade payables, ranks senior to all of our existing debt.

At June 30, 2003, outstanding borrowings under our revolving bank credit facility were $20 million together with $9.4 million in outstanding letter of credit obligations. A $9 million letter of credit was issued to a counter party to cover a margin call pursuant to a natural gas hedge contract. Subsequent to June 30, 2003, we repaid all outstanding borrowings under our revolving bank credit facility of $20 million and reduced our letter of credit obligations to $0.4 million. As of the date of this report, outstanding borrowings and letter of credit obligations under our revolving bank credit facility total $0.4 million.

Senior Subordinated Notes. On June 10, 2003, we issued in a private placement $175 million 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 which 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.

Upon closing of the $175 million 7% senior subordinated notes on June 10, 2003, we called our $100 million 8 5/8% notes due January 1, 2008 for redemption. The redemption of the $100 million in aggregate principal and payment of the premium for early redemption were funded with a portion of the proceeds received from the $175 million 7% senior subordinated notes and was completed on July 11, 2003. The $100 million 8 5/8% senior subordinated notes were issued on March 2, 1998. The notes bore interest at a rate of 8 5/8% per annum with interest payable semi-annually on January 1 and July 1. The $100 million 8 5/8% notes were redeemable, at our option, in whole or in part, at any time on or after January 1, 2003 at a price equal to 100% of the principal amount plus accrued and unpaid interest, if any, plus a specified premium which decreases yearly from 4.313% in 2003 to 0% in 2006. At June 30, 2003 and pursuant to the early redemption of the $100 million notes, we incurred debt extinguishment expenses totaling $5.9 million ($3.9 million net of tax) for the call premium of $4.3 million together with a non-cash charge of $1.6 million for the write-off of the balance of the unamortized issue costs. Total debt extinguishment expense of $5.9 million is included in the line item "Other (Income)Expense" on our Statement of Operations for the three month and six month periods ended June 30, 2003.

Contractual Obligations and Other Commercial Commitments

The table below summarizes our contractual obligations and commercial commitments at June 30, 2003. We have no "off-balance sheet" financing arrangements.

CONTRACTUAL OBLIGATIONS	AT JUNE 30, 2003 PAYMENTS DUE BY PERIOD 1 - 3 YEARS	4 - 5 YEARS	AFTER 5 YE
	($ IN THOUSANDS)		
Revolving bank credit facility	$ 20,000	$ --	$ --
8 5/8% senior subordinated notes, paid July 11, 2003 ..	100,000	--	--
7% senior subordinated notes, due June 2013	--	--	175,000
Operating leases	2,829	2,331	2,111
Total contractual obligations	$122,829	$ 2,331	$177,111

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Natural Gas and Oil Hedging

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 and historically, we have not experienced credit losses. We believe that our credit risk related to the 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. We may be subject to margin calls under our hedge contracts; however, we believe, we have sufficient liquidity to cover these margin calls, if any.

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 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 other income or expense.

The following table summarizes the change in the fair value of our derivative instruments for the six month period from January 1 to June 30, 2003 and 2002, respectively. Stated amounts do not reflect the effects of taxes.

CHANGE IN FAIR VALUE OF DERIVATIVES INSTRUMENTS	2003	2002
	(in thousands)	
Fair value of contracts at January 1	$(38,772)	$ 53,771
(Gain) loss on contracts realized	50,446	(16,978)
Fair value of new contracts when entered into during period	5,288	--
(Decrease) increase in fair value of all open contracts	(69,542)	(37,982)
Fair value of contracts outstanding at June 30, ...	$(52,580)	$ (1,189)

Natural Gas. The following table summarizes, on a monthly basis, our hedges currently in place for the remainder of 2003 and calendar 2004. For the remaining six months of 2003, we have hedged approximately 67% of our estimated production or a total of 190,000 MMBtu/day at a floor of $3.417/MMBtu and a ceiling of $4.548/MMBtu. For each month of 2004, we have also hedged approximately 67% of our estimated production or a total of 200,000 MMBtu/day. For the three months January through March 2004, our floor will average $4.375/MMBtu on 200,000 MMBtu/day and our ceiling will average $5.045/MMBtu on 100,000 MMBtu/day, with no ceiling on the remaining 100,000 MMBtu/day. For the remaining nine months of 2004, our floor will average $4.125/MMBtu on 200,000 MMBtu/day and our ceiling will average $6.023/MMBtu on 200,000 MMBtu/day. All amounts in the table below are in thousands, except for prices.

	OPTIONS - PUTS		FIXED PRICE SWAPS		C	
PERIOD	VOLUME (MMBTU)	NYMEX CONTRACT PRICE	VOLUME (MMBTU)	NYMEX CONTRACT PRICE	VOLUME (MMBTU)	C
						AVG
July 2003			1,240	$3.194	4,650	$3.
August 2003			1,240	3.194	4,650	3.
September 2003			1,200	3.194	4,500	3.
October 2003			1,240	3.194	4,650	3.
November 2003			1,200	3.194	4,500	3.
December 2003			1,240	3.194	4,650	3.
January 2004	3,100	$ 5.000			3,100	3.
February 2004	2,900	5.000			2,900	3.
March 2004	3,100	5.000			3,100	3.
April 2004					6,000	4.

May 2004	6,200	4.
June 2004	6,000	4.
July 2004	6,200	4.
August 2004	6,200	4.
September 2004	6,000	4.
October 2004	6,200	4.
November 2004	6,000	4.
December 2004	6,200	$4.

For natural gas, transactions are settled based upon the New York Mercantile Exchange or NYMEX price on the final trading day of the month. For oil, our swaps are settled against the average NYMEX price of oil for the calendar month rather than the last 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 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 our put option contracts, 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 period.

ITEM 4. CONTROLS AND PROCEDURES

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports we file under the Securities Exchange Act of 1934, as amended ("Exchange Act") is communicated, processed, summarized and reported within the time periods specified in the SEC's rules and forms. We carried out an evaluation, under the supervision and with the participation of our principal executive officer and principal financial officer, of the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15 of the Exchange Act), as of the end of the period covered by this report. Based on that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures are effective. There have been no changes in our internal control over financial reporting that

PART II. OTHER INFORMATION

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

On May 15, 2003, 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 10 Directors to serve until our next annual meeting:

DIRECTOR	VOTES FOR	VOTES WITHHELD
Gordon F. Ahalt	29,361,641	250,357
Robert B. Catell	26,225,712	3,386,286
David G. Elkins	29,362,541	249,457
Robert J. Fani	26,205,872	3,406,126
William G. Hargett	29,343,946	268,052
Harold R. Logan, Jr.	29,362,641	249,357
Gerald Luterman	29,343,356	268,642
H. Neil Nichols	29,343,256	268,742
James Q. Riordan	29,361,041	256,957
Donald C. Vaughn	29,406,792	205,206

2. The appointment of Deloitte & Touche LLP as our independent public accountants for the fiscal year ending December 31, 2003.

VOTES FOR	VOTES AGAINST	ABSTAINED
29,474,885	133,263	3,850

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ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K:

(a) Exhibits filed here with:

EXHIBITS		DESCRIPTION
10.1*	--	First Amendment to Credit Agreement among The Houston Exploration Company, the lenders Wachovia Bank, National Association, as issuing bank and as administrative agent, The Bank of Nova Scotia and Fleet National Bank, as co-syndication agents; and BNP Paribas, as documentation agent, effective June 5, 2003.
4.1	--	Indenture, dated as of June 10, 2003, between The Houston Exploration Company and the Bank of New York, as Trustee, with respect to the 7% Senior Subordinated Notes due 2013. (Exhibit 4.2 to our Registration Statement on Form S-4 (Registration No. 333-106836) and incorporated by reference).
4.2	--	Registration Rights Agreement dated as of June 5, 2003, among The Houston Exploration Company and Wachovia Securities, Inc., Lehman Brothers Inc., BNP Paribas Securities Corp., Fleet Securities, Inc. and Scotia Capital (USA) Inc., as Initial Purchasers. (Exhibit 4.5 to our Registration Statement on Form S-4 (Registration No. 333-106836) and incorporated by reference).

31.1*	--	Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	--	Certification of John H. Karnes, Senior Vice President and Chief Financial Officer, as required pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
32.1*	--	Certification of William G. Hargett, Chief Executive Officer, of 2002. as required pursuant to Section 906 of the Sarbanes -Oxley Act
32.2*	--	Certification of John H. Karnes, Senior Vice President and Chief Financial Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*	--	Filed herewith.

(b) Reports on Form 8-K:

Current Report on Form 8-K filed on February 21, 2003 to provide information in Item 5. - Other Events regarding a press release issued on February 21, 2003 announcing the offering by Houston Exploration of 3,000,000 shares of common stock in an underwritten public offering and concurrent repurchase of a like number of shares from KeySpan.

Current Report on Form 8-K filed February 26, 2003 to provide information in Item 5. - Other Events regarding the Underwriting Agreement between Houston Exploration and J.P. Morgan Securities, Inc. dated February 20, 2003 for the issuance and sale of 3,000,000 shares to the public and the Stock Purchase Agreement among Houston Exploration, KeySpan Corporation and THEC Holdings Corp. dated as of February 20, 2003 and in Item 7. - Financial Statements and Exhibits regarding the Underwriting Agreement and the Stock Purchase Agreement.

Current Report on Form 8-K filed on May 2, 2003 required by Item 12 and filed under Item 9 - Regulation FD Disclosure of our earnings release for the first quarter of 2003.

Current Report on Form 8-K filed on May 13, 2003 required by Item 5 - Other Events to amend the Current Reports filed Form 8-K for events dated February 20, 2003 and February 26, 2003 and to add exhibits 5.1 - Opinion of Andrews & Kurth L.L.P. and 23.1 - Consent of Andrews & Kurth L.L.P.

Current Report on Form 8-K filed on May 23, 2003 to provide information under Item 9 - Regulation FD Disclosure of our press release dated May 21,2003 announcing the results of a Gulf of Mexico discovery at High Island 115.

Current Report on Form 8-K filed on June 2, 2003 to provide information required by Item 5 - Other Events and Regulation FD Disclosure of selected financial data and a reconciliation of non-GAAP financial measures to GAAP measures.

Current Report on Form 8-K filed on July 18, 2003 to provide information required by Item 5 - Other Events and Regulation FD Disclosure of our press release announcing the completion of the redemption of our $100 million 8 5/8% senior subordinated notes due January 2008.

Current Report on Form 8-K filed on August 6, 2003 to provide information required by Item 12 - Results of Operations and Financial Condition of earnings release for the second quarter of 2003.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, hereunto duly authorized.

THE HOUSTON EXPLORATION COMPANY

By: /s/ William G. Hargett

Date: August 7, 2003

William G. Hargett
President and Chief Executive Officer

By: /s/ John H. Karnes

Date: August 7, 2003

John H. Karnes
Senior Vice President and Chief Financial Officer

By: /s/ James F. Westmoreland

Date: August 7, 2003

James F. Westmoreland
Vice President and Chief Accounting Officer

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INDEX TO EXHIBITS

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* -- Filed herewith