HOUSTON EXPLORATION CO
Form 10-Q
November 04, 2004

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

FORM 10-Q

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

For the quarterly period ended September 30, 2004

OR

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

For the transition period from _________ to _________

Commission File No. 001-11899

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

Delaware	**22-2674487**
(State or other jurisdiction of incorporation or organization)	**(IRS Employer Identification No.)**

1100 Louisiana 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 þ No o

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 þ No o

As of November 4, 2004, 28,229,624 shares of Common Stock, par value $.01 per share, were outstanding.

THE HOUSTON EXPLORATION COMPANY

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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 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. These forward-looking statements generally can be identified by words such as anticipate, believe, intend, expect, continue, estimate, may, project, will, or similar expressions. Forward-looking include all discussions under the caption Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations relating to:

- *future production;*
- *expected costs and expenses;*
- *anticipated capital expenditure;*
- *future cash flows and borrowings;*
- *pursuit of potential future acquisition opportunities; and*
- *sources of funding and the timing of exploration and development.*

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

- *the volatility of natural gas and oil prices;*
- *the requirement to take writedowns if natural gas and oil prices decline or if our finding and development costs continue to increase;*
- *the relatively short production lives of our reserves;*
- *our ability to find, develop and acquire natural gas and oil reserves;*
- *acquisition and investment risks;*
- *our ability to meet our substantial capital requirements;*
- *our outstanding indebtedness;*
- *the uncertainty of estimates of natural gas and oil reserves and production rates;*
- *the inherent hazards and risks involved in our operations;*
- *dependence upon operations concentrated in three primary areas;*
- *drilling risks;*
- *our hedging activities;*

compliance with environmental and other governmental regulations;

the competitive nature of our industry;

weather risks and other natural disasters;

our customers ability to meet their obligations; and,

the influence by our significant shareholder, KeySpan Corporation

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 for the year ended December 31, 2003. We undertake no obligation to publicly update or revise any forward-looking statements.

In this Quarterly Report, unless the context requires otherwise, when we refer to we, us or our , we are describing The Houston Exploration Company and through May 31, 2004, our subsidiary on a consolidated basis. Unless otherwise stated, all reserve and production quantities are expressed net to our interests.

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Part I. Financial Information
Item 1. Consolidated Financial Statements

THE HOUSTON EXPLORATION COMPANY

CONSOLIDATED BALANCE SHEETS
(in thousands, except share data)
(unaudited)

	September 30, 2004	December 31, 2003
Assets:		
Cash and cash equivalents	$ 4,321	$ 2,569
Accounts receivable	99,147	87,949
Accounts receivable Affiliate	5,284	6,733
Derivative financial instruments		3,458
Inventories	1,254	1,071
Deferred tax asset	41,825	19,644
Prepayments and other	5,299	5,818
Total current assets	157,130	127,242
Natural gas and oil properties, full cost method		
Unevaluated properties	151,259	134,491
Properties subject to amortization	2,533,937	2,324,011
Other property and equipment	11,189	12,617
	2,696,385	2,471,119
Less: Accumulated depreciation, depletion and amortization	1,293,206	1,099,990
	1,403,179	1,371,129
Other non-current assets	26,429	10,694
Total Assets	$1,586,738	$1,509,065
Liabilities:		
Accounts payable and accrued expenses	$ 118,992	$ 83,983
Derivative financial instruments	119,501	35,592
Asset retirement obligations	3,679	7,703
Total current liabilities	242,172	127,278
Long-term debt and notes	255,000	302,000

Derivative financial instruments	31,241	4,728
Deferred federal income taxes	276,054	251,425
Asset retirement obligations	87,861	84,654
Other deferred liabilities	12,036	3,446
Total Liabilities	904,364	773,531
Commitments and Contingencies (see Note 3)		
Stockholders Equity:		
Preferred Stock, $0.01 par value, 5,000,000 shares authorized, no shares issued		
Common Stock, $0.01 par value, 50,000,000 shares authorized and 28,187,424 shares issued and outstanding at September 30, 2004, and 31,437,581 shares issued and outstanding at December 31, 2003, respectively	281	315
Additional paid-in capital	255,161	366,781
Unearned compensation	(900)	(808)
Retained earnings	523,412	395,374
Accumulated other comprehensive income	(95,580)	(26,128)
Total Stockholders Equity	682,374	735,534
Total Liabilities and Stockholders Equity	$1,586,738	$1,509,065

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 September 30, 2004	Three Months Ended September 30, 2003	Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2003
	(unaudited)		(unaudited)	
Revenues:				
Natural gas and oil revenues	$162,472	$118,459	$486,684	$367,245
Other	288	428	734	1,277
Total revenues	162,760	118,887	487,418	368,522
Operating expenses:				
Lease operating	14,301	10,221	39,506	33,536
Severance tax	3,356	3,468	10,304	10,995
Transportation expense	3,006	2,576	8,911	7,764
Asset retirement accretion expense	1,098	827	3,576	2,479
Depreciation, depletion and amortization	66,926	47,327	195,082	140,705
General and administrative, net	5,679	5,437	21,528	13,525
Total operating expenses	94,366	69,856	278,907	209,004
Income from operations	68,394	49,031	208,511	159,518
Other (income) expense	(1,588)	(6,238)	(1,856)	(13,200)
Interest expense, net	2,000	1,842	6,593	6,268
Income before income taxes	67,982	53,427	203,774	166,450
Provision for taxes	24,984	18,708	75,736	58,339
Income before cumulative effect of change in accounting principle	42,998	34,719	128,038	108,111
Cumulative effect of change in accounting principle				(2,772)
Net income	$ 42,998	$ 34,719	$128,038	$105,339
Earnings per share:				
Net income per share basic				
Income before cumulative effect of change in accounting principle	$ 1.53	$ 1.12	$ 4.26	$ 3.48
Cumulative effect of change in accounting principle				(0.09)

Net income per share basic	$ 1.53	$ 1.12	$ 4.26	$ 3.39
Net income per share fully diluted				
Income before cumulative effect of change in accounting principle	$ 1.51	$ 1.11	$ 4.22	$ 3.47
Cumulative effect of change in accounting principle				(0.09)
Net income per share fully diluted	$ 1.51	$ 1.11	$ 4.22	$ 3.38
Weighted average shares outstanding basic	28,082	31,117	30,068	31,022
Weighted average shares outstanding fully diluted	28,486	31,236	30,330	31,134

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)

	Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2003
	(unaudited)	
Operating Activities:		
Net income	$ 128,038	$ 105,339
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	195,082	140,705
Deferred income tax expense	43,114	56,425
Asset retirement accretion expense	3,576	2,479
Ineffectiveness of derivative instruments	2,600	
Amortization of premium on derivative instruments	4,432	
Stock compensation expense	2,044	514
Debt extinguishment	211	1,626
Cumulative effect of change in accounting principle		2,772
Changes in operating assets and liabilities:		
(Increase) decrease in accounts receivable	(9,749)	407
(Increase) in inventories	(183)	(100)
(Increase) decrease in prepayments and other	519	(508)
(Increase) in other assets	(2,784)	(17,136)
Increase in accounts payable and accrued expenses	35,009	4,100
(Decrease) in ARO liability for assets retired and abandoned	(2,569)	
Increase in other deferred liabilities	8,590	1,468
Net cash provided by operating activities	407,930	298,091
Investing Activities:		
Investment in property and equipment	(302,380)	(212,933)
Deposit paid for property acquisition	(11,350)	(15,000)
Proceeds from dispositions	73,425	
Net cash used in investing activities	(240,305)	(227,933)
Financing Activities:		
Proceeds from long-term borrowings	247,000	246,000
Repayments of long-term borrowings	(294,000)	(323,000)
Debt issue costs	(1,555)	(4,586)
Proceeds from issuance of common stock from exercise of stock options	20,934	6,596
Proceeds from issuance of common stock	310,727	79,200
Exchange of common stock	(448,979)	
Repurchase of common stock		(79,200)

Net cash used in financing activities	(165,873)	(74,990)
Increase (decrease) in cash and cash equivalents	1,752	(4,832)
Cash and cash equivalents, beginning of period	2,569	18,031
Cash and cash equivalents, end of period	$ 4,321	$ 13,199
Supplemental Information:		
Cash paid for interest	$ 8,649	$ 11,278
Cash paid for income taxes	$ 35,900	$ 14,800

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

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THE HOUSTON EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

NOTE 1 Summary of Organization and Significant Accounting Policies

Our Business

We are an independent natural gas and oil company engaged in the exploration, development, exploitation and acquisition of natural gas and oil reserves in North America. Natural gas is our primary focus. Our primary areas of operations are South Texas, offshore in the shallow waters of the Gulf of Mexico and the Arkoma Basin of Oklahoma and Arkansas. During 2003, we began operations in the Rocky Mountain region, with a current focus on the Uinta Basin of Northeastern Utah and the DJ Basin of Eastern Colorado. In February 2004, we divested our South Louisiana assets and in June 2004, we divested our Appalachian Basin assets in connection with the KeySpan Exchange transaction described below.

We were founded by KeySpan Corporation in December 1985 and completed an initial public offering in 1996. KeySpan is a diversified energy provider whose principal natural gas distribution and electric generation operations are located in the Northeastern United States. As a result of an asset exchange transaction with KeySpan completed on June 2, 2004, and described below, KeySpan s ownership in the outstanding shares of our common stock was reduced from approximately 54% to 24%. KeySpan s ownership interest in our common stock was further reduced to 23% at September 30, 2004 as a result of the dilutive effect of stock options exercised during the third quarter of 2004. KeySpan has publicly announced it does not consider its investment in our company to be a core asset and that it may therefore decide from time to time to sell part of its investment in our shares.

KeySpan Exchange and Offering

On June 2, 2004, we completed an asset exchange transaction with KeySpan pursuant to which we redeemed and cancelled 10,800,000 shares of our common stock owned by KeySpan in exchange for all the stock of Seneca-Upshur Petroleum, Inc., our wholly-owned subsidiary, to which we contributed all of our Appalachian Basin assets valued at $60 million and $389 million in cash for a total exchange value of $449 million. This transaction is referred to as the KeySpan Exchange. The KeySpan Exchange is intended to qualify as a tax-free exchange under Section 355(a) of the Internal Revenue Code.

To fund the cash portion of the exchange, on June 2, 2004, we sold 6,200,000 shares of our common stock in a registered public offering at $48.00 per share, (the Offering) and contributed to Seneca-Upshur substantially all of the net proceeds from the Offering for a total of $282 million together with an additional $107 million of proceeds from bank borrowings. We then conveyed to KeySpan all of the shares of Seneca-Upshur in exchange for 10,800,000 shares of our common stock.

On June 23, 2004, the underwriters of our Offering exercised a portion of their over-allotment option and we sold an additional 620,000 shares of common stock at $48.00 per share for net proceeds of $28.6 million. The proceeds from the over-allotment were used to reduce bank borrowings.

Our redemption and cancellation of the 10,800,000 shares received from KeySpan and our issuance of 6,820,000 new shares resulted in a net 3,980,000 decrease in the outstanding shares of our common stock, and thereby reduced KeySpan s ownership from approximately 54% to 24%. As a result of the KeySpan Exchange and Offering, our bank borrowings increased by a net $79 million and we incurred approximately $5.1 million in compensation and other expenses related to special bonuses awarded to executives and key employees who assisted in structuring and consummating the transactions. Finally, KeySpan agreed to reduce its representation on our Board of Directors from five to two directors. Our Chief Executive Officer, William G. Hargett, was elected Chairman of the Board replacing Robert B. Catell, Chairman and Chief Executive Officer of KeySpan, who still remains on the Board.

Principles of Consolidation

On June 2, 2004, all of the shares of our wholly-owned subsidiary, Seneca-Upshur, were conveyed to KeySpan in connection with the KeySpan Exchange. Subsequent to the transaction, Seneca-Upshur is no longer a subsidiary of Houston Exploration but is a wholly-owned subsidiary of KeySpan, and as a result, our financial statements reflect the consolidated results of Seneca-Upshur through May 31, 2004. Seneca-Upshur was our only subsidiary, and prior to the KeySpan Exchange, our consolidated financial statements included our accounts and the accounts of Seneca-Upshur. All significant inter-company balances and transactions were eliminated.

Seneca-Upshur is in the exploration and production business in West Virginia with interests in Appalachian Basin assets. As of December 31, 2003, we had 50.5 Bcfe of estimated proved reserves in the Appalachian Basin. Because we account

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

for our natural gas and oil assets under the full cost method of accounting, the disposition of our Appalachian Basin assets, which represented only a portion of our full cost pool, is not considered discontinued operations under the Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) 144.

Interim Financial Statements

Our balance sheet at September 30, 2004, and the statements of operations and cash flows for the periods indicated herein have been prepared without audit, pursuant to the rules and regulations of the Securities and Exchange Commission (SEC). Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States (GAAP) have been condensed or omitted, although we believe that the disclosures contained herein are adequate to make the information presented not misleading. The balance sheet at December 31, 2003, is derived from the December 31, 2003, 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, 2003.

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

Use of Estimates

The preparation of the consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the dates of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Estimates of our remaining proved natural gas and oil reserves are one of our most significant financial estimates. Estimates of proved reserves are key components of our depletion rate for natural gas and oil properties and our full cost ceiling test limitation. Because there are numerous uncertainties inherent in the estimation process, actual results could differ materially from these estimates.

Business Segment Information

SFAS 131, Disclosures about Segments of an Enterprise and Related Information establishes standards for reporting information about operating segments. All of our operations involve the exploration, development and production of natural gas and oil and all of our operations are located in the United States. We have a single, company-wide management team that administers all properties as a whole rather than as discrete operating segments. We measure financial performance as a single enterprise and not on an area-by-area basis. Consequently, while we compile and analyze basic operational data by area, we do not prepare separate financial statement information by area and are not, therefore, required to report separate business segment information under SFAS 131.

Revenue Recognition

We use the entitlements method of accounting for the recognition of natural gas and oil revenues. Under this method of accounting, income is recorded based on our net revenue interest in production or nominated deliveries. We incur production gas volume imbalances in the ordinary course of business. Net deliveries in excess of entitled amounts are recorded as liabilities, while net under deliveries are reflected as assets. Imbalances are reduced either by subsequent recoupment of over-and-under deliveries or by cash settlement, as required by applicable contracts. Production imbalances are marked-to-market at the end of each month at the lowest of (i) the price in effect at the time of production; (ii) the current market price; or (iii) the contract price, if a contract is in hand.

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Net Income Per Share

Basic earnings per share is calculated by dividing net income by the weighted average number of shares of common stock outstanding during the period. No dilution for any potentially dilutive securities is included. Fully diluted earnings per share is calculated by applying the treasury stock method to adjust the average number of common shares outstanding for the dilutive effect, if any, of the assumed conversion of potentially convertible securities.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	**2003**	**2004**	**2003**
	(in thousands, except per share data)			
Numerator:				
Income before cumulative effect of change in accounting principle	$42,998	$34,719	$128,038	$108,111
Cumulative effect of change in accounting principle				(2,772)
Net income	$42,998	$34,719	$128,038	$105,339
Denominator:				
Weighted average shares outstanding	28,082	31,117	30,068	31,022
Add dilutive securities: Stock options	404	119	262	112
Total weighted average shares outstanding and dilutive securities	28,486	31,236	30,330	31,134
Earnings per share basic:				
Income before cumulative effect of change in accounting principle	$ 1.53	$ 1.12	$ 4.26	$ 3.48
Cumulative effect of change in accounting principle				(0.09)
Net income per share basic	$ 1.53	$ 1.12	$ 4.26	$ 3.39
Earnings per share fully diluted:				
Income before cumulative effect of change in accounting principle	$ 1.51	$ 1.11	$ 4.22	$ 3.47
Cumulative effect of change in accounting principle				(0.09)

Net income per share fully diluted	$ 1.51	$ 1.11	$ 4.22	$ 3.38

The calculation of shares outstanding for fully diluted EPS does not include the effect of outstanding stock options to purchase 404,001 and 1,843,150 shares for the three months ended September 30, 2004 and 2003, respectively, and 907,956 and 1,880,107 shares for the nine months ended September 30, 2004 and 2003, respectively, because to include would have an antidilutive effect on earnings per share.

Comprehensive Income

Comprehensive Income includes Net Income and certain items recorded directly to Stockholders Equity and Classified as Other Comprehensive Income. The table below summarizes Comprehensive Income and provides the components of the change in Accumulated Other Comprehensive Income for the three-month and nine-month periods ended September 30, 2004 and 2003, respectively.

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2004	**2003**	**2004**	**2003**
	(in thousands)			
Net income	$ 42,998	$34,719	$128,038	$105,339
Other comprehensive income (loss)				
Derivative instruments settled and reclassified, net of tax	7,034	6,276	23,153	39,066
Ineffectiveness of open derivative instruments, net of tax.	585		1,690	
Change in fair value of open derivative instruments, net of tax	(35,309)	19,906	(94,295)	(25,297)
Total other comprehensive income (loss)	(27,690)	26,182	(69,452)	13,769
Comprehensive income	$ 15,308	$60,901	$ 58,586	$119,108

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Natural Gas and Oil Properties

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

- full cost pool (including assets associated with retirement obligations); plus,
- estimates for future development costs; less,
- unevaluated properties and their related costs; less,
- estimates for salvage.

Costs associated with unevaluated properties are excluded from the amortization base until we have made a determination as to the existence of proved reserves. We review our unevaluated properties at the end of each quarter to determine whether the costs incurred should be reclassified to the full cost pool and thereby subject to amortization. Sales of natural gas and oil properties are accounted for as adjustments to the full cost pool, with no gain or loss recognized, unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves.

Under full cost accounting rules, total capitalized costs are limited to a ceiling equal to the present value of future net revenues, discounted at 10% per annum, plus the lower of cost or fair value of unproved properties less income tax effects (the ceiling limitation). We perform a quarterly ceiling test to evaluate whether the net book value of our full cost pool exceeds the ceiling limitation. If capitalized costs (net of accumulated depreciation, depletion and amortization) less related deferred taxes are greater than the discounted future net revenues or ceiling limitation, a writedown or impairment of the full cost pool is required. A writedown of the carrying value of the full cost pool is a non-cash charge that reduces earnings and impacts stockholders equity in the period of occurrence and typically results in lower depreciation, depletion and amortization expense in future periods. Once incurred, a writedown is not reversible at a later date.

The ceiling test is calculated using natural gas and oil prices in effect as of the balance sheet date and adjusted for basis or location differential, held constant over the life of the reserves. We use derivative financial instruments that qualify for cash flow hedge accounting under SFAS 133 to hedge against the volatility of natural gas prices, and in accordance with SEC guidelines, we include estimated future cash flows from our hedging program in our ceiling test calculation. In addition, subsequent to the adoption of SFAS 143, Accounting for Asset Retirement Obligations, the future cash outflows associated with settling asset retirement obligations are not included in the computation of the discounted present value of future net revenues for the purposes of the ceiling test calculation.

Unevaluated Properties. The costs associated with unevaluated properties and properties under development are not initially included in the amortization base and relate to unproved leasehold acreage, seismic data, wells and production facilities in progress and wells pending determination together with interest costs capitalized for these projects.

Unevaluated leasehold costs are transferred to the amortization base with the costs of drilling the related well or upon expiration of a lease. Costs of seismic data are allocated to various unproved leaseholds and transferred to the amortization base with the associated leasehold costs on a specific project basis. Costs associated with successful wells in progress and wells pending determination are transferred to the amortization base once a determination is made whether or not proved reserves can be assigned to the property. Costs of dry holes are transferred to the amortization base immediately upon determination that the well is unsuccessful. All items included in our unevaluated property balance are assessed on a quarterly basis for possible impairment or reduction in value. We believe that substantially all of the costs included in our unevaluated property balance will be evaluated in the next four years.

Classification of Intangible Leasehold Costs

In September 2004, FASB issued FASB Staff Position (FSP) FAS 142-2, Application of FASB Statement 142, Goodwill and Other Intangible Assets to Oil and Gas Producing Entities. This FSP was issued as a result of questions arising as to whether the scope exception in paragraph 8(b) of SFAS 142 includes the balance sheet classification and disclosures for drilling and mineral rights of oil and gas producing entities. The FSP FAS 142-2 concludes that the scope

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(unaudited)

exception in SFAS 142 does extend to the balance sheet classification and disclosure provisions for drilling and mineral rights of oil and gas producing entities that are within the scope of SFAS 19, Financial Accounting and Reporting by Oil and Gas Producing Companies. As a result, mineral rights held under lease or other contractual arrangements together with cash costs for the acquisition of natural gas and oil leasehold interests are not required to be separately classified as intangibles on the balance sheet. Historically, we have included these types of intangible leasehold costs as a component of natural gas and oil properties, which is consistent with the FSP. As such, our consolidated financials statements were not affected.

Asset Retirement Obligations

On January 1, 2003, we adopted SFAS 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 (ARO) 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 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 and an adjustment is made to the full cost pool. 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. Subsequent to our adoption of SFAS 143, the ARO assets, which are carried on the balance sheet as part of the full cost pool, have been included in our amortization base for the purposes of calculating depreciation, depletion and amortization expense. For the purposes of calculating the ceiling test, the future cash outflows associated with settling the ARO liability have been excluded from the computation of the discounted present value of estimated future net revenues.

The following table describes the various components of our ARO liability during each of the nine-month periods ending September 30, 2004 and 2003, respectively. ARO liability includes amounts classified as both current and long-term.

	Nine Months Ended September 30,	
	2004	2003
	(in thousands)	
ARO liability at January 1	$ 92,357	$57,197
Additions from drilling	4,982	4,852
ARO accretion expense	3,576	2,478
Assets acquired	7,626	
Assets sold	(12,714)	
Assets retired and abandoned	(4,287)	
ARO liability at September 30	$ 91,540	$64,527

Derivative Instruments and Hedging Activities

Our hedging policy does not permit us to hold derivative instruments for trading purposes. In our hedging program, we utilize a variety of derivative instruments, including swaps, collars and options. We generally place contracts with major financial institutions and other credit-worthy counterparties. Although our hedging program protects a portion of our cash flows from downward price movements, certain hedging strategies, specifically the use of swaps and collars, may also limit our ability to realize the full benefit of future price increases. In addition, because our derivative instruments are typically indexed to New York Mercantile Exchange (NYMEX) prices as opposed to the index price where the gas is actually sold, our hedging strategy may not protect our cash flows if the price differential increases between the NYMEX price and index price for the point of sale.

Our derivative instruments are designated cash flow hedges and qualify for hedge accounting under SFAS 133, Accounting for Derivative Instruments and Hedging Activities, as amended, and, accordingly, we carry the fair market value of our derivative instruments on the balance sheet as either an asset or liability and defer unrealized gains or losses in accumulated other comprehensive income. Gains and losses are reclassified from accumulated other comprehensive income to the income statement as a component of natural gas and oil revenues in the period the hedged production occurs. If any

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ineffectiveness occurs, amounts are recorded directly to the income statement. For the first nine months of 2004, our net income includes an unrealized loss of $2.6 million ($1.7 million net of tax), of which $0.9 million ($0.6 million net of tax) was incurred during the third quarter of 2004, which represents the ineffective portion of our derivative instruments that were not eligible for deferral. The ineffectiveness was a result of changes at the end of the current period in the price differentials between the index price of the derivative contract, which uses a NYMEX index, and index price for the point of sale for the cash flow that is being hedged, the majority of which is the Houston Ship Channel index.

Based on market prices at September 30, 2004, we recorded an unrealized loss in Accumulated Other Comprehensive Income of $95.6 million, net of tax, representing the fair value of our open contracts. Any loss be will realized in future earnings at the time of the related sales of natural gas production applicable to specific hedges. However, these amounts could vary materially as a result of changes in market conditions.

Accounting for Stock Options and Restricted Stock

Effective January 1, 2003, we adopted the fair value expense recognition provisions of SFAS 123, Accounting for Stock Based Compensation, as amended by SFAS 148, Accounting for Stock Based Compensation Transition and Disclosure using the prospective method as defined by the SFAS 148. As a result, we now record as compensation expense the fair value of all stock options issued subsequent to January 1, 2003. No expense has been recorded for grants made in previous years.

For the three months ended September 30, 2004 and 2003, we recognized gross compensation expense of $0.7 million and $0.4 million, respectively, for stock options and restricted stock granted during these periods of which we capitalized $0.2 million and $7,000, in each of the respective three-month periods. For the corresponding nine-month periods ended September 30, 2004 and 2003, gross compensation expense for stock options was $2.0 million and $0.5 million, respectively, of which we capitalized $0.5 million and $24,000, respectively.

Prior to our January 1, 2003, adoption of SFAS 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 123, compensation expense would have had the following pro forma effect on our net income and earnings per share for the three-month and nine-month periods ended September 30, 2004 and 2003. Amounts are in thousands, except per share data.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	(in thousands, except per share data)			
Net income as reported	$42,998	$34,719	$128,038	$105,339
Add: Stock-based compensation expense included in net income, net of tax	361	268	1,016	334
Less: Stock-based compensation expense using fair value method, net of tax	(1,266)	(1,107)	(3,999)	(2,189)

Net income pro forma	$42,093	$33,880	$125,055	$103,484
Net income per share as reported	$ 1.53	$ 1.12	$ 4.26	$ 3.39
Net income per share fully diluted as reported	1.51	1.11	4.22	3.38
Net income per share pro forma	$ 1.50	$ 1.09	$ 4.16	$ 3.34
Net income per share fully diluted pro forma	1.48	1.08	4.12	3.32

The pro forma results for each of the periods presented above is not necessarily indicative of future effects on Net Income and Earnings per Share.

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NOTE 2 Long-Term Debt and Notes

	September 30, 2004	December 31, 2003
	(in thousands)	
Senior Debt:		
Revolving bank credit facility, due April 1, 2008	$ 80,000	$ 127,000
Subordinated Debt:		
7% senior subordinated notes, due June 15, 2013	175,000	175,000
Total long-term debt and notes	$255,000	$ 302,000

The carrying amount of borrowings outstanding under the revolving bank credit facility approximates fair value as the interest rates are tied to current market rates. At September 30, 2004, the quoted market value of our $175 million of 7% senior subordinated notes was 98.0% of the $175 million carrying value or $171.5 million.

Revolving Bank Credit Facility

We maintain a revolving bank credit facility with a syndicate of lenders led by Wachovia Bank, National Association, as issuing bank and administrative agent, The Bank of Nova Scotia and Fleet National Bank as co-syndication agents and BNP Paribas and Comerica Bank as co-documentation agents. The credit facility was amended and restated on April 1, 2004, primarily to increase the size of the facility and was then amended again on June 2, 2004, in conjunction with the KeySpan Exchange. As amended, the facility provides us with a commitment of $400 million, which may be increased at our request and with prior approval from Wachovia to a maximum of $450 million. Amounts available for borrowing under the credit facility are limited to a borrowing base. On April 1, 2004, our borrowing base was increased from $300 million to $375 million, and on June 2, 2004, was reduced from $375 million to $340 million as a result of the disposition of our Appalachian Basin assets. Pursuant to the reduction in our borrowing base, we incurred $0.2 million debt extinguishment expenses during the second quarter of 2004 relating to the write-off of a portion of our debt issue costs. The $0.2 million is included in the line item Other (income) expense on our Statement of Operations. Effective October 15, 2004, the $340 million borrowing base was increased to $400 million, which is expected to remain in effect until the next scheduled redetermination on April 1, 2005. Up to $40 million of the borrowing base is available for the issuance of letters of credit. Outstanding borrowings are unsecured and rank senior in right of payment to our $175 million 7% subordinated notes. The amended facility matures on April 1, 2008. At September 30, 2004, we had $80 million in outstanding borrowings under the credit facility and $0.4 million in outstanding letter of credit obligations. Subsequent to September 30, 2004, we borrowed an additional $95 million under the credit facility and issued additional letters of credit totaling $8.1 million (see Note 7 Subsequent Events). As of the date of our report, outstanding borrowings under our credit facility were $175 million and letter of credit obligations were $8.5 million.

Interest rates, margins and terms of payment remained unchanged from prior periods pursuant to the April 1, 2004, amendment. Interest is payable on borrowings under our revolving bank credit facility, as follows:

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

on fixed rate loans, a fixed rate equal to the sum of (a) a quoted LIBOR rate divided by one minus the average maximum rate during the interest period set for certain reserves of member banks of the Federal Reserve System in Dallas, Texas, plus (b) a variable margin between 1.25% and 2.00%, depending on the amount of borrowings outstanding under the credit facility.

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

Our revolving bank credit facility contains customary negative covenants that place restrictions and limits on, among other things, the incurrence of debt, guarantees, liens, leases and certain investments. 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

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

At September 30, 2004, and December 31, 2003, we were in compliance with all covenants.

Senior Subordinated Notes

On June 10, 2003, we issued $175 million of 7% senior subordinated notes due June 15, 2013. The notes bear interest at a rate of 7% per annum with interest payable semi-annually on June 15 and December 15, beginning December 15, 2003. We may redeem the notes at our option, in whole or in part, at any time on or after June 15, 2008, at a price equal to 100% of the principal amount plus accrued and unpaid interest, if any, plus a specified premium that decreases yearly from 3.5% in 2008 to 0% in 2011 and thereafter. In addition, at any time prior to June 15, 2006, we may redeem up to a maximum of 35% of the aggregate principal amount with the net proceeds of one or more equity offerings at a price equal to 107% of the principal amount, plus accrued and unpaid interest and liquidated damages, if any. The notes are general unsecured obligations and rank subordinate in right of payment to all existing and future senior debt, including the revolving bank credit facility, and will rank senior or equal in right of payment to all existing and future subordinated indebtedness.

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

- incurrence of additional indebtedness and issuance of preferred stock;
- repayment of certain other indebtedness;
- payment of dividends or certain other distributions;
- investments and repurchases of equity;
- use of the proceeds of assets sales;
- transactions with affiliates;
- creation, incurrence or assumption of liens;
- merger or consolidation and sales or other dispositions of all or substantially all of our assets;
- entering into agreements that restrict the ability of our 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.

NOTE 3 Commitments and Contingencies

Legal Proceedings

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

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NOTE 4 Related Party Transactions

KeySpan Exchange

To facilitate the KeySpan Exchange (see Note 1 *KeySpan Exchange and Offering*), we entered into a Distribution Agreement with KeySpan that defines each company s rights and obligations with respect to the exchange transaction. The Distribution Agreement contains, among other provisions, customary representations and warranties concerning our Appalachian Basin properties, including title, regulatory compliance and environmental matters, along with limited indemnification obligations. Pursuant to the Distribution Agreement, the two companies also entered into a Tax Matters Agreement, which generally provides that each party would be responsible for its own tax consequences if the KeySpan Exchange fails to qualify as a tax-free transaction. In addition, we entered into a Transition Services Agreement pursuant to which we will provide KeySpan with transitional services with respect to the Appalachian Basin assets for a fee of $27,000 per month until March 31, 2005. Finally, we amended and restated our registration rights agreement with KeySpan. KeySpan is restricted from increasing their ownership of our shares (approximately 6.6 million shares subsequent to the exchange transaction) for a period of three years.

NOTE 5 Acquisitions and Dispositions

BP Acquisition

On September 30, 2004, we completed the purchase of two producing offshore fields from BP Exploration & Production Inc. The net purchase price of $30.0 million was paid in cash and financed by borrowings under our revolving bank credit facility. The $31.5 million purchase price was reduced by $1.5 million for various customary closing items, including revenues received by and expenditures made by the seller related to the properties acquired for the period between the effective date of the transaction, August 1, 2004, and the closing date, September 30, 2004. The properties acquired are located at Eugene Island 240 and Main Pass 264 and each block has one producing platform. Total proved reserves associated with the interests acquired are approximately 16.2 Bcfe as of September 30, 2004, of which 85% are natural gas. Our average working interest is 85% and we will operate both blocks.

Orca Acquisition

On September 17, 2004, we entered into a definitive purchase and sale agreement to acquire natural gas and oil producing properties primarily located in the shallow waters of the Gulf of Mexico from Orca Energy, L.P. for a cash purchase price of approximately $113.5 million, subject to certain post-closing adjustments. The purchase price consists of the payment of (i) a deposit of $11.4 million, which was paid on September 17, 2004 (which deposit generally is nonrefundable, except upon certain breaches of the agreement by the seller) and (ii) an additional $102.1 million payable upon closing of the transaction, which is subject to certain post-closing adjustments. We borrowed the amount of the deposit under our revolving bank credit facility. At September 30, 2004, the deposit of $11.4 million was included in the line item Other Assets on our Balance Sheet. The acquisition was completed on October 29, 2004. See Note 7 Subsequent Events *Orca Acquisition*.

Disposition and Exchange of Appalachian Basin Assets

In connection with the KeySpan Exchange on June 2, 2004 (see Note 1 *KeySpan Exchange and Offering*), we divested all of our Appalachian Basin assets with an agreed upon value of $60 million. Pursuant to an Asset Contribution Agreement, we contributed to Seneca-Upshur all of the assets relating solely to our Appalachian Basin assets that were not already owned by Seneca-Upshur, and Seneca-Upshur assumed all of the liabilities relating to the Appalachian Basin assets for which it was not already liable. In the KeySpan Exchange, all of the stock of Seneca-Upshur was then conveyed to KeySpan and effective June 1, 2004, Seneca-Upshur became an indirect wholly-owned subsidiary of KeySpan.

Our Appalachian property base was located primarily in central West Virginia and included the Belington, Clarksburg and Seneca Upshur Fields located in Barbour, Randolph, Upshur and Mingo Counties of West Virginia and included the assets acquired on December 31, 2003, from EnerVest East Limited Partnership located adjacent to our existing base in the Crawford and Pennsboro Fields in Lewis, Harrison, Tyler and Ritchie Counties of West Virginia and the Waynesburg and Yatesboro Fields in Greene and Armstrong Counties of southwestern Pennsylvania. Based on internal estimates at June 1, 2004, our Appalachian Basin properties had 51.2 Bcfe of estimated proved reserves, and our average daily production was

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approximately 8 MMcfe/day, which represented approximately 3% of our total daily production. We had approximately 207,000 gross (129,000 net) acres under lease and owned working interests in approximately 1,414 gross (1,035 net) wells, of which we operated approximately 92%. Our average working interest was 73%.

Sale of Onshore South Louisiana Properties

On February 4, 2004, we completed the sale of our onshore South Louisiana producing properties. The sale was effective November 1, 2003, and the properties represented 12.3 Bcfe proved reserves as of December 31, 2003, and included interests in 33 gross (9.5 net) producing wells and covered approximately 6,300 gross (2,300 net) acres. The sale price of $15 million was reduced by $1.9 million for various customary closing items, including revenues received by and expenditures made by us related to the properties sold for the period between the effective date of the transaction and the closing date. The net proceeds of $13.1 million from the sale were used to repay borrowings under our revolving bank credit facility.

NOTE 6 Stockholders Rights Plan

On August 12, 2004, we adopted a stockholder rights plan designed to assure that our stockholders receive fair and equal treatment in the event of an unsolicited attempt to takeover our company and to protect against abusive or coercive takeover tactics that are not in the best interest of our company or its stockholders. To implement the rights plan, the Board of Directors declared a dividend of one preferred share purchase right for each outstanding share of our common stock to stockholders of record as of the close of business on August 23, 2004, and directed the issuance of one preferred share purchase right with respect to each share of our common stock that shall become outstanding thereafter until the rights become exercisable or they expire as described below. Each right initially represents a contingent right to purchase, under certain circumstances, one one-thousandth of a share of our Series A Junior Participating Preferred Stock, par value $.01 per share, at an initial exercise price of $275.00 per one one-thousandth of a share, subject to adjustment under certain circumstances. The rights will become exercisable and trade independently from our common stock upon the public announcement of the acquisition by a person or group of 10% or more of our common stock, or ten days after commencement of a tender or exchange offer that would result in the acquisition of 10% or more of our common stock (or, in the case of KeySpan and its affiliates, more than 24% of our common stock).

Each share purchased upon exercise of the rights will be entitled to a minimum quarterly preferential dividend payment of the greater of (i) $10.00 per share and (ii) an amount equal to 1,000 times the dividend declared per share of common stock. Each share will be entitled to 1,000 votes, voting together with the common stock. In the event of our liquidation, each share of the Series A Junior Participating Preferred Stock will be entitled to a minimum preferential payment of the greater of (a) $10.00 per share (plus any accrued but unpaid dividends) and (b) an amount equal to 1,000 times the payment made per share of common stock.

If we are acquired in a merger or other business combination transaction after a person or group has acquired 10% or more of our common stock, each right will entitle its holder to purchase, at the rights exercise price, that number of the acquiring company s shares of common stock having a market value of twice the right s exercise price. In addition, if a person or group acquires 10% or more of our common stock, each right will entitle its holder (other than the acquiring person or group) to purchase, at the right s exercise price, a number of fractional shares of the Series A Junior Participating Preferred Stock or shares of our common stock having a market value of twice the right s exercise price.

The rights expire on August 12, 2014, unless redeemed earlier by our Board of Directors. The Board of Directors can redeem the rights at a price of $.01 per right at any time before the rights become exercisable, and thereafter only in limited circumstances.

NOTE 7 Subsequent Events

Orca Acquisition

On October 29, 2004, we completed the acquisition of certain producing properties from Orca Energy, L.P. (see Note 5 Acquisitions and Dispositions *Orca Acquisition*). At closing, we borrowed $70 million on our revolving bank credit facility and used cash on hand of $28.4 million, for a total of $98.4 million, to fund the remaining portion of the $109.8 million net purchase price. In September 2004, we paid a cash deposit of $11.4 million towards the purchase price of $113.5 million which was reduced at closing by $3.7 million for various customary closing items, including revenues received by and expenditures made by

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the seller related to the properties acquired for the period between the effective date of the transaction, August 1, 2004, and the closing date, October 29, 2004.

The Orca properties consist of 12 producing fields, two of which are non-operated and located onshore in central Mississippi: the Wausau Field located in Wayne County and the Oakvale Dome Field located in Jefferson Davis County. The offshore fields are a mix of state and federal leases located in less than 50 feet of water and include seven blocks in federal waters and three blocks in state waters. Total acreage acquired covers 23,777 gross (17,973 net) acres. The properties include 15 platforms, five production caissons and 28 producing wells. Based on internal estimates, proved reserves are an estimated 62.5 Bcfe, of which 81% are natural gas. Our average working interest in the properties acquired is 68% and we will operate approximately 85% of the proved reserves acquired.

Letter of Credit Issued for Hedging Activities

Subsequent to the balance sheet date, the fair value of our open derivative contracts increased beyond our available credit limit with one counterparty. As a result, in October 2004, we were required to issue letters of credit totaling $8.1 million to further guarantee our performance on open derivative contracts.

Shelf Registration Statement Filed

On October 27, 2004, we filed a second shelf registration statement with the SEC to register the sale from time to time of up to an additional $477.4 million of our common stock, preferred stock, depositary shares and debt securities, or any combination thereof. The SEC has not declared this registration statement effective. The prospectus for the second shelf registration statement will include the unused portion of the shelf registration statement filed in March 2004 of $272.4 million together with the registration of the remaining 6,580,392 shares of our common stock held by KeySpan. The combination of the two shelf registrations statements will provide an aggregate of $750 million for the offering of our common stock, preferred stock, depositary shares and debt securities, or a combination of any of these securities.

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

The following discussion is intended to assist you in understanding our business and the results of operations together with our present financial condition. This section should be read in conjunction with our Consolidated Financial Statements and the accompanying notes included elsewhere in this Quarterly Report on Form 10-Q, as well as our Annual Report on Form 10-K for the year ended December 31, 2003.

Statements in our discussion may be forward-looking. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause future production, revenues and expenses to differ materially from our expectations. See Forward-Looking Statements at the beginning of this Quarterly Report and Risk Factors Affecting Our Business found on page 13 of our Annual Report on Form 10-K for additional discussion of some of these factors and risks.

Overview of Our Business

We are an independent natural gas and oil company engaged in the exploration, development, exploitation and acquisition of natural gas and oil reserves in North America. Natural gas is our primary focus. Our primary areas of operations are South Texas, offshore in the shallow waters of the Gulf of Mexico and the Arkoma Basin of Oklahoma and Arkansas. During 2003, we began operations in the Rocky Mountain region, with a current focus on the Uinta Basin of Northeastern Utah and the DJ Basin of Eastern Colorado. In February 2004, we divested our South Louisiana assets and in June 2004, we divested our Appalachian Basin assets in connection with the KeySpan Exchange transaction described in Note 1 *Our Business KeySpan Exchange and Offering*. We operate as one segment as each of our operating areas has similar economic characteristics and each meets the criteria for aggregation as defined in the Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) 131.

At December 31, 2003, our net proved reserves were 755 billion cubic feet equivalent or Bcfe, with a present value, discounted at 10% per annum, of cash flows before income taxes of $2.0 billion. As of December 31, 2003, we had 50.5 Bcfe of estimated proved reserves in the Appalachian Basin and 12.3 Bcfe of estimated proved reserves in South Louisiana. Our reserves are fully engineered on an annual basis by independent petroleum engineers. Approximately 94% of our net proved reserves at December 31, 2003, were natural gas, approximately 68% of which were classified as proved developed. We operate approximately 85% of our producing wells.

Source of Our Revenues

We derive our revenues from the sale of natural gas and oil that is produced from our natural gas and oil properties. Revenues are a function of the volume produced and the prevailing market price at the time of sale. The price of natural gas is the primary factor affecting our revenues. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we utilize derivative instruments to hedge future sales prices on a significant portion of our natural gas production. For the first nine months of 2004, the use of certain types of derivative instruments has prevented us from realizing the full benefit of upward price movements and may continue to do so in future periods.

Principal Components of Our Cost Structure:

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

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

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

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

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

Income Taxes. We are generally subject to a 35% federal income tax rate. For income tax purposes, we are allowed deductions for accelerated depreciation, depletion and intangible drilling costs that reduce our current tax liability. Prior to 2003, all of our taxes, both federal and state, were deferred; however, during 2003, we utilized all of our net operating loss carryforwards and as a result, we recognized current income tax expense and will continue to recognize current tax expense as long as we are generating taxable income.

Critical Accounting Estimates

Proved Reserves. Our most significant financial estimates are based on estimates of proved natural gas and oil reserves. Estimates of proved reserves are key components of our unevaluated properties, our rate for recording depreciation, depletion and amortization and our full cost ceiling limitation. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future revenues, rates of production and timing of development expenditures, including many factors beyond our control. The estimation process relies on assumptions and interpretations of available geologic, geophysical, engineering and production data and the accuracy of reserve estimates is a function of the quality and quantity of available data. Our reserves are fully engineered on an annual basis by independent petroleum engineers.

Unevaluated Properties. The balance of unevaluated properties is comprised of capital costs incurred for undeveloped acreage, seismic data, wells and production facilities in progress, wells pending determination and related capitalized interest. These costs are initially excluded from our amortization base until the outcome of the project has been determined, or generally, until it is known whether proved reserves will or will not be assigned to the property. We assess all items in our unevaluated property balance on a quarterly basis for possible impairment or reduction in value. We believe that substantially all of the costs included in our unevaluated property balance will be evaluated in the next four years.

Asset Retirement Obligations. Asset retirement obligations represent the estimated future abandonment costs of tangible long-lived assets such as platforms, wells, service assets, pipelines, and other facilities. We estimate the fair value of an asset s retirement obligation in the period in which the liability is incurred, if a reasonable estimate can be made. We employ a present value technique to estimate the fair value of an asset retirement obligation, which reflects certain assumptions, including an inflation rate, our credit-adjusted, risk-free interest rate, the estimated settlement date of the liability and the estimated current cost to settle the liability which we compute from third party quotes. Changes in timing or to the original estimate of cash flows will result in changes to the carrying amount of the liability.

Derivative Instruments. Under SFAS 133, Accounting for Derivative Instruments and Hedging Activities, as amended, we reflect the fair market value of our derivative instruments on our balance sheet. Our estimates of fair value are determined by obtaining independent market quotes from third parties, as well as utilizing a Black-Scholes option valuation model that is based upon underlying forward price curve data, a risk-free interest rate and estimated volatility factors.

Recent Accounting Developments

In September 2004, the FASB issued FASB Staff Position (FSP) FAS 142-2, Application of FASB Statement 142, Goodwill and Other Intangible Assets to Oil and Gas Producing Entities. This FSP was issued as a result of questions arising as to whether the scope exception in paragraph 8(b) of SFAS 142 includes the balance sheet classification and disclosures for drilling and mineral rights of oil and gas producing entities. The FSP FAS 142-2 concludes that the scope exception in SFAS 142 does extend to the balance sheet classification and disclosure provisions for drilling and mineral rights of oil and gas producing entities that are within the scope of SFAS 19, Financial Accounting and Reporting by Oil and Gas Producing Companies. As a result, mineral rights held under lease or other contractual arrangements together with cash costs for the acquisition of natural gas and oil leasehold interests are not required to be separately classified as intangibles on the balance sheet. Historically, we have included these types of intangible leasehold costs as a component of natural gas and oil properties, which is consistent with the FSP. As such, our consolidated financials statements were not affected.

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Overview of Third Quarter 2004

Continued strong energy commodity prices combined with production growth in all of our primary areas (South Texas, offshore Gulf of Mexico and the Arkoma Basin) were the primary factors behind results for operations, earnings and cash flows during the third quarter of 2004. The increase in our cash flows allowed for continued deployment of capital for drilling, an increase in our capital expenditure budget and the continued repayment of bank debt. During the third quarter of 2004:

We generated $43.0 million in net income, an increase of 24% from the third quarter of 2003;

We produced a total of 31.5 Bcfe and increased our average daily production rate by 19% quarter-over-quarter to 343 MMcfe per day, while production decreased by 9 MMcfe per day or 3% sequentially from an average of 351 MMcfe per day during the second quarter of 2004 primarily as a result of the divesture of our Appalachian Basin assets in June 2004 as part of the KeySpan Exchange transaction (see Note 1 KeySpan Exchange and Offering);

We generated $162.6 million in net cash flows from operating activities, invested a net $136.7 million in natural gas and oil properties including $30 million for producing property acquisitions and we reduced borrowings under our revolving bank credit facility by a net $30 million;

We completed the acquisition of 330,000 net acres in Colorado s DJ Basin and drilled the first two of the 20 wells planned during the remainder of 2004;

We completed the acquisition of two offshore producing blocks from BP Exploration & Production Inc for a net $30.0 million and added estimated proved reserves of 16.2 Bcfe (see Note 5 Acquisitions and Dispositions);

We entered into a definitive purchase and sale agreement with Orca Energy, L.P to acquire 12 producing fields located primarily in the shallow waters of the central Gulf of Mexico with an estimated 62.5 Bcfe of proved reserves for $113.5 million (see Note 7 Subsequent Events);

We drilled 68 wells, of which 58 or 85% were successful, with 21 successful wells in Arkoma, 19 in South Texas, 12 in the Rockies and 6 offshore;

We increased our 2004 capital expenditure budget by $185 million from the $315 million established at the beginning of 2004 to $500 million, of which $55 million is expected to provide for additional exploration, and development and $130 million provided for the BP and Orca producing property acquisitions; and

We adopted a shareholder rights plan designed to assure that our stockholders receive fair and equal treatment in the event of an unsolicited takeover attempt and to protect against abusive or coercive takeover tactics that are not in the best interest of our company or its stockholders (see Note 6 Stockholders Rights Plan).

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Summary Operating Information:	Three Months Ended September 30, 2004	2003	Variance		Nine Months Ended September 30, 2004	2003	Variance	
	(in thousands)							
Operating revenues	$162,760	$118,887	$43,873	37%	$487,418	$368,522	$118,896	32%
Operating expenses	94,366	69,856	24,510	35%	278,907	209,004	69,903	33%
Income from operations	68,394	49,031	19,363	39%	208,511	159,518	48,993	31%
Net income	42,998	34,719	8,279	24%	128,038	105,339	22,699	22%
Production:								
Natural gas (MMcf)	29,465	24,554	4,911	20%	87,735	73,573	14,162	16%
Oil (MBbls)	343	331	12	4%	995	916	79	9%
Total (MMcfe) (1)	31,523	26,540	4,983	19%	93,705	79,069	14,636	19%
Average daily production (MMcfe/d)	343	288	55	19%	342	290	52	18%
Average Sales Prices:								
Natural Gas (per Mcf) realized (2)	$ 5.06	$ 4.45	$ 0.61	14%	$ 5.15	$ 4.64	$ 0.51	11%
Natural Gas (per Mcf) unhedged	5.46	4.84	0.62	13%	5.59	5.45	0.14	3%
Oil (per Bbl) realized (2)	38.69	27.70	10.99	40%	34.98	28.24	6.74	24%
Oil (per Bbl) unhedged	38.69	27.70	10.99	40%	34.98	28.68	6.30	22%

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

(2) Average realized prices include the effect of hedges.

Natural Gas and Oil Revenues

For the third quarter of 2004, the 37% increase in operating revenues was a result of the combination of the 19% increase in production and the 14% increase in realized natural gas prices. Correspondingly, for the first nine months of 2004, the 32% increase in operating revenues was a combination of the 19% increase in production and the 11% increase in realized natural gas prices as our loss from hedging activities narrowed for the nine-month period by $21.8 million.

Production Volume

The 19% increase in production for the current quarter is a result of newly developed production, both onshore and offshore, combined with the production added from Gulf of Mexico properties acquired during the fourth quarter of 2003 from Transworld Exploration and Production Inc.

Onshore, our daily production rates increased 8% from an average of 172 MMcfe per day during the third quarter of 2003 to 185 MMcfe per day during the third quarter of 2004 despite our loss of approximately 8 MMcfe per day or 5% for the current quarter as a result of the divesture of our South Louisiana and Appalachian Basin properties during the first half of 2004. In the Arkoma Basin, we are experiencing the full impact of the accelerated drilling program initiated in 2003 as we added 14 MMcfe per day in newly developed production. With three rigs drilling since the beginning of 2004, Arkoma production reached a record of 38 MMcfe per day during the third quarter compared to 24 MMcfe per day during the third quarter of 2003. In South Texas, with six rigs drilling, we also experienced production growth as we added approximately 7 MMcfe per day. South Texas production increased to an average of 145 MMcfe per day during the third quarter of 2004 compared to 138 MMcfe per day in the third quarter of 2003.

Offshore, our production increased 36% from an average of 116 MMcfe per day during the third quarter of 2003 to an average of 158 MMcfe per day during the third quarter of 2004. We added 51 MMcfe per day in newly developed production, of which 28 MMcfe per day was attributable to development drilling at High Island A283. During the quarter, we completed and brought on-line our seventh development well at High Island A283 since January 2004. High Island A283 was acquired in mid-October 2003, as part of our acquisition of Gulf of Mexico properties from Transworld. The acquired production from the Transworld properties accounted for approximately 30 MMcfe per day of our third quarter offshore production increase. Offsetting the increases from the newly developed and the acquired production were declines from existing and maturing fields totaling 39 MMcfe per day. Sequentially, from second quarter 2004 to third quarter 2004, offshore production declined from an average of 160 MMcfe per day to 158 MMcfe per day. The third quarter decline is a direct result of the deferral of approximately 210,000 or 2 MMcfe per day caused by shut-ins for Hurricane Ivan in September 2004. All of our shut-in production has been fully restored.

For the nine-month period ended September 30, 2004, our total average daily production increased 18% from 290 MMcfe per day during the first nine months of 2003 to 342 MMcfe per day during the corresponding nine-month period of 2004. During the first nine months of 2004, we divested of a net 3 MMcfe per day with the sale of our South Louisiana properties in February and the exchange of our Appalachian Basin properties in June and we added 12 MMcfe per day in Arkoma, 6 MMcfe per day in South Texas and 37 MMcfe per day offshore. Offshore, the increase is comprised of:

46 MMcfe per day in newly developed production from new wells brought on-line since the end of the third quarter of 2003 at High Island 47, A283 and 115; Galveston Island 389/424 and 390; Eugene Island 159 and East Cameron 280;

30 MMcfe per day in acquired production as a result of the Transworld acquisition in mid-October 2003; offset in part by,

a decline of 39 MMcfe per day in production from existing and maturing fields.

Commodity Prices and Effects of Hedging

Our average unhedged or sales price for natural gas increased by 13% from $4.84 per Mcf during the third quarter of 2003 to $5.46 per Mcf during the third quarter 2004.

Included in natural gas revenues for the third quarter of 2004 is a loss of $11.7 million from natural gas hedging activities, which includes an unrealized loss of $0.9 million representing the ineffective portion of our derivative instruments that are not eligible for deferral under SFAS 133. As a result of the loss from hedging activities, we realized an average natural gas price during the third quarter of 2004 of $5.06 per Mcf that was 93% or $0.40 lower than our average sales price. For the third quarter of 2003, we incurred a hedge loss from natural gas derivatives of $9.7 million resulting in an average realized price of $4.45 per Mcf that was 92% or $0.39 per Mcf lower than our sales price.

For the first nine months of 2004, the increase in our realized price for natural gas was primarily a result of the narrowing of our losses from hedging activities for the period as average sales prices increased slightly by 3% from an average of $5.45 per Mcf during the first nine months of 2003 to $5.59 Mcf during the first nine months of 2004. Our natural gas hedge loss for the first nine months of 2004 of $38.2 million decreased by 36% or by $21.5 million from the loss of $59.7 million during the first nine months of 2003. For the first nine months of 2004, our realized price was 92% or $0.44 per Mcf lower than our average unhedged natural gas price, which compares to a realized price during the first nine months of 2003 that was 85% or $0.81 per Mcf lower than the unhedged price.

Operating Expenses

Overall, on an absolute dollar basis, our total operating expenses increased by 35% during the third quarter of 2004 and by 33% for the current nine-month period and on a unit of production basis, by 14% for the quarter and 13% for the period. The increase in total operating expenses is a result of continued growth and expansion of operations as our production base has grown on a compound basis through drilling and acquisitions. Lease operating expense is higher primarily as a result of our fourth quarter 2003 Gulf of Mexico acquisition. Severance taxes are slightly lower primarily as a result of the disposition of our Appalachian Basin and South Louisiana assets during the first half of

2004. Depreciation, amortization and depletion expense is higher due to higher finding and development costs. And, general and administrative expenses are higher due to expansion of our workforce combined with an increase in employee benefit and incentive compensation expenses.

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	Three Months Ended September 30,				Nine Months Ended September 30,			
Operating Expenses per Mcfe	**2004**	**2003**	**Variance**		**2004**	**2003**	**Variance**	
Lease operating expense	$0.45	$0.39	$ 0.06	15%	$0.42	$0.42	$	%
Severance tax	0.11	0.13	(0.02)	-15%	0.11	0.14	(0.03)	-21%
Transportation expense	0.10	0.10		%	0.10	0.10		%
Asset retirement accretion expense	0.03	0.03		%	0.04	0.03	0.01	33%
Depreciation, depletion and amortization	2.12	1.78	0.34	19%	2.08	1.78	0.30	17%
General and administrative, net	0.18	0.20	(0.02)	-10%	0.23	0.17	0.06	35%
Total operating expenses per unit of production	$2.99	$2.63	$ 0.36	14%	$2.98	$2.64	$ 0.34	13%

Lease Operating Expense. On an absolute dollar basis, lease operating expense increased by 40% for the third quarter of 2004 and by 18% for the nine-month period. During 2004, we have experienced higher lease operating expenses primarily as a result of our fourth quarter 2003 Gulf of Mexico acquisition and the continuing maturation of our existing property base. While expenses during 2004 are at higher levels than in the previous year, the 19 % increase in production volume for both the current quarter and nine-month period has resulted in lower than expected per unit expense as expenses are spread over a greater production base. For the third quarter of 2004, the $0.06 or 15% increase in lease operating expense per Mcfe was due to workover expenses incurred during the current quarter and an increase in ad valorem taxes. Ad valorem taxes are higher as property valuations have increased during 2004 as a result of sustained higher commodity prices. For the nine-month period, lease operating expense per Mcfe is unchanged at $0.42.

Severance Tax. Severance tax is a function of volume and revenues generated from onshore production. Severance tax decreased by 3% quarter-over-quarter and by 6% period-over-period. On an Mcfe basis, severance tax decreased by $0.02 or 15% for the quarter and by $0.03 of 21% for the nine-month period. Despite the increase in Arkoma production (our South Texas properties are exempt or taxed at reduced rates because of their high-cost/tight-sand designation received in July 2002) and higher wellhead prices, severance tax expense is lower primarily as a result of the disposition of our Appalachian Basin and South Louisiana assets during the first half of 2004.

Depreciation, Depletion and Amortization. The increase in our depreciation, depletion and amortization expense for the current quarter and the first nine months of 2004 was primarily a result of a higher depletion rate combined with a 19% increase in production for the current quarter and for the current nine-month period. The increase in our depletion rate is primarily a result of higher finding costs and fewer reserve additions. During the first nine months of 2004, we drilled a total of 25 dry holes, of which 19 were development wells and six were exploratory. In addition, for the third quarter of 2004, we estimate that $0.05 of the increase in the rate was due to the disposition of our Appalachian Basin assets, which based on interim internal reserves estimates, represented 51.2 Bcfe in total net proved reserves as of June 1, 2004.

Asset Retirement Accretion Expense. The increase in ARO accretion expense during the third quarter of 2004 and the nine month period is primarily a result of additions to our ARO liability since the end of the third quarter of 2003 of approximately $36.8 million from the acquisition of the Gulf of Mexico properties in October 2003, West Virginia properties in December 2003 and Gulf of Mexico properties during the third quarter of 2004 offset in part by $17.0 million in reductions during the first nine months of 2004 as a result of abandonment of offshore properties and the disposition of our South Louisiana properties in February 2004 and our Appalachian Basin properties in June 2004.

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

	Three Months Ended September 30,				Nine Months Ended September 30,			
General and Administrative per Mcfe	**2004**	**2003**	**Variance**		**2004**	**2003**	**Variance**	
Gross general and administrative expense	$ 0.32	$ 0.34	$(0.02)	-6%	$ 0.37	$ 0.31	$ 0.06	19%
Operating overhead reimbursements	(0.02)	(0.01)	(0.01)	100%	(0.02)	(0.01)	(0.01)	100%
Capitalized general and administrative	(0.12)	(0.12)		%	(0.12)	(0.12)		%
General and administrative expense, net	$ 0.18	$ 0.21	$(0.03)	-14%	$ 0.23	$ 0.18	$ 0.05	28%

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For the quarter, net general and administrative expenses on an absolute dollar basis are up by 4%. Aggregate general and administrative expenses are 13% higher for the third quarter of 2004 primarily as a result of increases in employee benefits and incentive and stock compensation expenses. The increase in incentive compensation is a function of the company s performance and our ability to meet established objectives for the year. The increase in stock compensation expense is a result of our adoption of the fair value expense provisions for stock options under SFAS 123, as amended, in January 2003. While general and administrative expenses are increasing as our company continues to grow, the decrease in general and administrative expense per Mcfe of $0.02 for the current quarter is a result of the increase in production volume.

For the nine-month period, net general and administrative expenses are up by 59% on an absolute dollar basis. In addition to increases in payroll, benefits, stock option and incentive compensation expenses, more than half of the percentage increase for the current nine-month period was due to approximately $4.4 million in additional compensation expenses incurred during the second quarter of 2004 as a result of the KeySpan Exchange transaction. The additional compensation expenses included $4.1 million in special bonuses awarded to executives and key employees who assisted in structuring and consummating the KeySpan Exchange and the Offering. In addition, we incurred $0.3 million in expenses relating to the accelerated vesting of restricted stock held by directors who resigned or retired from our Board of Directors in June. On a per-unit of production basis, these additional compensation expenses resulted in a $0.05 increase for the first nine months of 2004. Excluding the effect of the additional compensation expenses, gross general and administrative expense for the first nine months of 2004 would have been $0.32 per Mcfe and net general and administrative expense would have been $0.18 reflecting increases of $0.01 or 3% for gross general and administrative expense per Mcfe and no change for net general and administrative expenses per Mcfe.

Other Income and Expense, Interest and Taxes

Other Income and Expense. For the third quarter of 2004, other income and expense is comprised of refunds relating to prior years severance tax expense of $1.6 million ($1.0 million net of tax) that compares to $6.2 million ($4.0 million net of tax) recorded during the third quarter of 2003. In July 2002, we applied for and received from the Railroad Commission of Texas a high-cost/tight-gas formation designation for a portion of our South Texas production. For qualifying wells, production is either exempt from tax or taxed at a reduced rate until certain capital costs are recovered. For 2004, the recognition of other income as a result of the recoupment of prior years expense is considerably less than in 2003 as we are nearing the end of the recoupment process. For the nine month period of 2004, Other Income and Expense includes two items: (i) income of $2.1 million ($1.4 million net of tax) related to refunds of prior year s severance tax expense; and (ii) debt extinguishment expenses of $0.2 million incurred pursuant to the reduction of the borrowing base on our revolving bank credit facility from $375 million to $340 million during the second quarter of 2004. The credit facility is reserve based and contains certain restrictions limiting the sale of assets, and due to the disposition of our Appalachian Basin assets as a component of the KeySpan Exchange, our borrowing base was reduced. For the corresponding nine months of 2003, Other Income and Expense includes: (i) debt extinguishment expenses totaling $5.9 million ($3.9 million net of tax) incurred pursuant to the call and early redemption of our $100 million 8?% senior subordinated notes due 2008; and (ii) income of $19.1 million ($12.4 million net of tax) related to refunds of prior year s severance tax expense.

Interest Expense, Net of Capitalized Interest.

	Three Months Ended September 30,			Nine Months Ended September 30,		
Interest and Average Borrowings	**2004**	**2003**	**Variance**	**2004**	**2003**	**Variance**

				(in thousands)				
Gross interest	$ 4,162	$ 3,868	$ 294	8%	$ 12,771	$ 11,486	$ 1,285	11%
Capitalized interest	(2,162)	(2,026)	(136)	7%	(6,178)	(5,218)	(960)	18%
Interest expense, net of capitalized	$ 2,000	$ 1,842	$ 158	9%	$ 6,593	$ 6,268	$ 325	5%
Average borrowings	$265,207	$194,908	$70,299	36%	$269,920	$224,665	$45,255	20%
Average interest rate	5.79%	7.20%	(1.41)%	-20%	5.69%	6.29%	(0.60)%	-10%

For the third quarter of 2004, the increase in gross interest expense is due to an increase in bank borrowings offset in part by a decrease in our average interest rate. Bank debt averaged $90 million at a rate of 3.6 % during the third quarter of 2004 compared to an average of $20 million at 2.50% during the third quarter of 2003. Bank debt was higher during the current quarter primarily as a result of borrowings during the second quarter of 2004 used to fund a portion of the KeySpan Exchange transaction completed in June. For the nine-month period of 2004, the increase in gross interest expense is due to an increase in both fixed debt and bank debt offset in part by a decrease in average interest rates. Our fixed debt increased in June 2003 when we replaced our existing senior subordinated notes of $100 million at 8?% with new senior subordinated notes of $175 million at 7%. Bank borrowings averaged $95 million at a rate if 3.46% during the first nine months of 2004 compared to an average of $85 million at 3.42% for the first nine months of 2003. Bank debt has increased as we utilized our revolving bank credit facility to fund not only a portion of the KeySpan Exchange in June 2004 but also several producing property acquisitions since the end of the third quarter of 2003. Capitalized interest is a function of unevaluated properties and the increase for the current quarter and the nine-month period of 2004 corresponds to the increase in our average unevaluated property balance for these periods. The increase in unevaluated property is primarily a result of our October 2003 acquisition of Gulf of Mexico producing properties from Transworld combined with an increase in projects in-progress as of the end of the current period.

Income Tax Provision. Our provision for taxes includes both state and federal taxes. For the current year, our state tax obligations have increased as our onshore revenues have increased and as we have expanded our operations into several Rocky Mountain States. The 34% increase in income taxes for the third quarter of 2004 corresponds to the 27% increase in income before taxes. Our current provision increased to $7.9 million as we utilized all of our net operating loss carryforwards during 2003 and moved to a tax paying status. Prior to the third quarter of 2003, the majority of our federal income taxes were deferred. For the nine-month period of 2004 income taxes increased by 30%, which corresponds to the 22% increase in income before taxes. Our current provision for the nine-month period increased to $32.6 million and includes $1.0 million relating to nondeductible executive compensation expense incurred as a result of a special bonus paid to our Chief Executive Officer in connection with the KeySpan Exchange.

Liquidity

Capital Requirements

Our principal requirements for capital are to fund our capital investment program and to satisfy our contractual obligations, primarily the repayment of long-term debt. Our capital investments include the following:

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

At the regular quarterly meeting of our Board of Directors held on October 22, 2004, the 2004 capital expenditure budget was increased by $185 million from an initial level of $315 million to $500 million. The increase will cover additional exploration and development expenditures as well as the BP and Orca producing property acquisitions. To maintain flexibility of our capital program, we do not enter into material long-term obligations with any of our drilling contractors or services providers. However, with increasing service costs we may find it advantageous in the future to contract a drilling rig or well service with some type of guarantee that would obligate us to a minimum level of activity. As the remainder of the year progresses, we will continue to evaluate our capital spending. Actual levels may vary due to a variety of factors, including drilling results, natural gas prices, economic conditions and future acquisitions.

During the first nine months of 2004, we invested $301.4 million in natural gas and oil properties, which includes $30 million for the BP acquisition completed in September, and $1.0 million in other property and equipment. We divested $73.4 million in onshore assets, which included our South Louisiana assets in February and our Appalachian Basin assets in June. Capital expended for non-natural gas and oil properties includes the improvements to our Houston office space, upgrades to our information technology systems and equipment, and purchases of vehicles. In addition, we invested $11.4 million in the form of a deposit toward the acquisition of additional producing natural gas and oil properties that was completed on October 29, 2004 (see Note 5 Acquisitions and Dispositions *Orca Acquisition*.)

During the first nine months of 2004, we completed the drilling of 167 gross wells (139.6 net) of which 85% or 142 (119.0 net) were successful and 25 (20.6 net) were unsuccessful, with an additional 10 wells (8.5 net) in progress at the end of the period. During the third quarter, we drilled 68 gross wells (58.2 net) of which 85% or 58 (49.8 net) were successful and 10 (8.4 net) were unsuccessful. The table below details the components of our natural gas and oil expenditures during each of three-month and nine-month periods ended September 30, 2004 and 2003.

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Natural Gas and Oil Expenditures:	Three Months Ended September 30, 2004	Three Months Ended September 30, 2003	Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2003
	(in thousands)			
Producing property acquisitions	$ 30,042	$	$ 32,742	$
Leasehold and lease acquisition costs (1)	17,427	17,186	44,063	45,458
Development	63,858	44,139	180,558	122,906
Exploration	25,327	12,630	44,026	43,347
Total natural gas and oil capital expenditures	136,654	73,955	301,389	211,711
Producing property dispositions	(287)		(72,854)	
Net natural gas and oil capital expenditures	$136,367	$73,955	$228,535	$211,711

(1) For the three months ended September 30, 2004 and 2003, leasehold costs include capitalized interest and general and administrative expenses of $6.0 million and $5.1 million, respectively. For the corresponding nine-month periods of 2004 and 2003, capitalized interest and general and administrative expenses included in leasehold costs totaled $17.8 million and $14.9 million, respectively.

Future Commitments

In addition to our capital expenditure program, we are committed to making cash payments in the future on two types of contracts: note agreements and operating leases. We do not have off balance sheet debt or other unrecorded obligations, and we have not guaranteed the debt of any other party. The table below provides estimates of the timing of future payments that we were obligated to make based on agreements in place at September 30, 2004. In addition to the contractual obligations listed on the table below, our balance sheet at September 30, 2004 reflects accrued interest payable on our revolving bank credit facility of approximately $10,000, which is payable over the next 90-day period. We expect to make annual interest payments of $12.5 million per year on our $175 million of 7% senior subordinated notes due June 2013. We anticipate making income tax payments of approximately $7 million to $10 million during the fourth quarter of 2004.

	At September 30, 2004 — Payments Due by Period				
	Total	1 year or less	2 3 years	4 5 years	after 5 years
	(in thousands)				
Contractual Obligations:					
	$ 80,000	$	$	$80,000	$

Revolving bank credit facility, due April 2008					
7% senior subordinated notes, due June 2013	175,000				175,000
Operating leases	7,437	394	4,499	2,544	
Producing property acquisition Orca, payable October 29, 2004 [1]	109,800	109,800			
	372,237	110,194	4,499	82,544	175,000
Other Long-Term Obligations:					
Asset retirement obligations	91,540	3,679	8,284	16,303	63,274
Total contractual obligations and commitments	$463,777	$113,873	$12,783	$98,847	$238,274

(1) See Note 7 Subsequent Events *Orca Acquisition.*

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Capital Resources

We intend to fund our capital expenditure program and contractual commitments through cash flows from our operations and borrowings under our revolving bank credit facility. If additional funding is needed to complete a significant acquisition, we may also access public markets for debt or equity. Our primary sources of cash during the first nine months of 2004 were funds generated from operations and proceeds for the issuance of common stock through our public offering of 6.8 million shares of common stock and from the exercise of stock options. Cash was used to fund the KeySpan Exchange, exploration and development expenditures, producing property acquisitions and to reduce debt under our revolving bank credit facility. We made aggregate cash payments of $8.6 million for interest and $35.9 million for taxes.

The following table summarizes the sources of cash during each of the nine-month periods ended September 30, 2004 and 2003:

	Nine Months Ended September 30,			
	2004	2003	Variance	% change
	(in thousands)			
Net income	$ 128,038	$ 105,339	$ 22,699	22%
Non-cash charges	251,059	204,521	46,538	23%
Cash from operations before changes in operating assets and liabilities	379,097	309,860	69,237	22%
Decrease (increase) in operating assets and liabilities	28,833	(11,769)	40,602	-345%
Net cash provided by operating activities	407,930	298,091	109,839	37%
Net cash (used) for investments in property and equipment	(240,305)	(227,933)	(12,372)	5%
Net cash (used) in financing activities	(165,873)	(74,990)	(90,883)	121%
Net increase (decrease) in cash	$ 1,752	$ (4,832)	$ 6,584	-136%

At September 30, 2004, we had a working capital deficit of $85.0 million, long-term debt of $255 million (which includes $80 million in bank debt), and $259.6 million of borrowing capacity available under our revolving bank credit facility. The working capital deficit was primarily a result of a current liability of $119.5 million representing the fair value of our derivative instruments. The fair value of our derivative instruments will fluctuate with commodity prices, and as commodity prices increase, our liquidity exposure tends to increase as a result of open derivative instruments. Consequently, we are more likely to have the largest unfavorable mark-to-market position in a high commodity price environment. Our working capital balance fluctuates as a result of the timing and amount of cash receipts and disbursements for operating activities and borrowings or repayments under our revolving bank credit facility. As a result, we often have a working capital deficit or a relatively small amount of positive working capital.

The increase in net cash provided by operating activities during the first nine months of 2004 was primarily attributable to the increase in operating income primarily as a result of the 19% increase in production for the current year combined with the 11% increase in realized natural gas prices and a decrease in our hedge loss. The fluctuations in operating assets and liabilities are caused by the timing of cash receipts and disbursements.

Access to Capital Markets. In March 2004, we filed a shelf registration statement with the SEC for the offering, from time to time, of up to $600 million of our common stock, preferred stock, depositary shares and debt securities, or a combination of any of these securities, as well as for the shares of our common stock owned by KeySpan. Subsequent to the June 2004 public offering of 6.8 million shares at $48.00 per share, the proceeds of which were used to finance a portion of the KeySpan Exchange transaction, we have approximately $272.4 million of capacity remaining under this shelf registration statement.

On October 27, 2004, we filed a second shelf registration statement with the SEC for the offering, from time to time, of up to an additional $477.4 million of our stock or debt securities, which registration has not been declared effective by the SEC. The prospectus for the second shelf registration statement will include the unused portion of the shelf registration statement filed in March 2004 of $272.4 million together with the registration of the remaining 6,580,392 shares of our common stock held by KeySpan. The combination of the two shelf registrations statements will provide an aggregate of $750 million for the offering of our common stock, preferred stock, depositary shares and debt securities, or a combination of any of these securities.

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We believe that operating cash flow and our credit facility will be adequate to meet our capital and operating requirements for the remaining portion of 2004. We continuously monitor our working capital and debt position as well as coordinate our capital expenditure program with expected cash flows and projected debt repayment schedules. Although we have no specific budget for future property acquisitions, should attractive opportunities arise, we believe we could finance the additional capital expenditures with cash on hand, operating cash flow, additional borrowing under our revolving bank credit facility, issuances of additional equity or debt securities or development with industry partners.

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. We believe that our credit risk related to our natural gas futures and swap contracts is no greater than the risk associated with the primary contracts and that the elimination of price risk reduces volatility in our reported results of operations, financial position and cash flows from period to period and lowers our overall business risk; however, as a result of our hedging activities we may be exposed to greater credit risk in the future.

Our hedges are cash flow hedges and qualify for hedge accounting under SFAS 133 and, accordingly, we carry the fair market value of our derivative instruments on the balance sheet as either an asset or liability and defer unrealized gains or losses in accumulated other comprehensive income. Gains and losses are reclassified from accumulated other comprehensive income to the income statement as a component of natural gas and oil revenues in the period the hedged production occurs. If any ineffectiveness occurs, amounts are recorded directly to natural gas and oil revenues. During the first nine months of 2004, we recognized $2.6 million of ineffectiveness, of which $0.9 million was recognized during the third quarter. The ineffectiveness was a result of changes at the end of the current period in the price differentials between the index price of the derivative contract, which uses a NYMEX index, and the index price for the point of sale for the cash flow that is being hedged, the majority of which is the Houston Ship Channel index.

Subsequent to the balance sheet date, the fair value of our open derivative contracts increased beyond our available credit limit with one counterparty. As a result, in October 2004, we were required to issue letters of credit totaling $8.1 million to further guarantee our performance on open derivative contracts.

Change in Fair Value of Derivative Instruments

The following table summarizes the change in the fair value of our derivative instruments for each of the nine-month periods from January 1 to September 30, 2004 and 2003, and provides the fair value at the end of each period.

	Nine Months Ended September 30, 2004		Nine Months Ended September 30, 2003	
Change in Fair Value of Derivatives Instruments:	**Before Tax**	**After Tax**	**Before Tax**	**After Tax**

		(in thousands)		
Fair value of contracts at January 1	$ (36,862)	$(23,960)	$(38,772)	$(25,202)
Realized (gain) loss on contracts settled	35,620	23,153	60,102	39,066
Unrealized (gain) loss due to ineffectiveness of contracts	2,600	1,690		
Fair value of new contracts when entered into during period			5,288	3,437
(Decrease) in fair value of all open contracts	(152,100)	(98,865)	(38,919)	(25,297)
Fair value of contracts outstanding at September 30	$(150,742)	$(97,982)	$(12,301)	$ (7,996)

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Derivatives in Place as of the Date of Our Report

The following table summarizes, our natural gas hedges in place for 2004, 2005, 2006, 2007 and 2008. For the remaining three months of 2004, we estimate that approximately 70% of our expected future production is hedged and for calendar 2005, we have hedged approximately 74% of our expected future production. Volumes listed in the table below represent daily volumes.

Natural Gas Hedges	Fixed Price Swaps		Collars		
		NYMEX		NYMEX	
Period	Daily Volume (MMBtu)	Contract Price	Daily Volume (MMBtu)	Contract Price[1] Floor	Ceiling
October December 2004	40,000	$4.960	200,000	$4.125	$6.023
January December 2005	80,000	5.304	180,000	4.833	6.434
January December 2006	30,000	5.893	60,000	5.500	7.248
January December 2007			30,000	5.000	6.597
January December 2008			20,000	5.000	5.720

(1) For collars, price represents a weighted average for outstanding contracts.

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

With respect to any particular swap transaction, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price for the transaction, and we are required to make payment to the counterparty if the settlement price for any settlement period is greater than the swap price for the transaction. For any particular collar transaction, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price for the transaction, and we are required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling price for the transaction. We are not required to make or receive any payment in connection with a collar transaction if the settlement price is between the floor and the ceiling. For option contracts, we have the option, but not the obligation, to buy contracts at the strike price up to the day before the last trading day for that NYMEX contract.

Item 4. Controls and Procedures

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 Securities and Exchange Commission s rules and forms. We carried out an evaluation under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-14 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, as of September 30, 2004, our disclosure controls and procedures are functioning effectively as designed. There have been no significant changes in our internal control over financial reporting that occurred during the most recent fiscal quarter prior to the end of the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Part II. Other Information.

Item 5. Other information.

On October 22, 2004, the Compensation Committee of our Board of Directors granted to each of our nine executive officers a combination of restricted stock and options. These grants were annual grants made as part of each executive s annual

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compensation package as defined under the terms of each executive s employment agreement with our company. The grants were made pursuant to the terms of our 2004 Long-Term Incentive Plan that was approved by stockholders in June 2004. We received waivers from all nine of our executive officers that under terms of the waiver allowed us to issue to each executive a combination of restricted stock and stock options that was equal in value to a grant of only stock options. Waivers were received from Messrs. Hargett, Adcock, Karnes, Lindsey, Mueller, Price, Rice, Schwartz and Westmoreland.

Item 6. Exhibits:

Exhibits	Description
10.1	Purchase and Sale Agreement, dated September 17, 2004, between The Houston Exploration Company and Orca Energy, L.P. (filed as exhibit 2.1 to our Current Report on Form 8-K dated November 1, 2004 (File No. 007-11899) and incorporated by reference).
10.2	Rights Agreement, dated as of August 12, 2004, between The Houston Exploration Company and The Bank of New York, as Rights Agent (filed as exhibit 4.1 to our Current Report on Form 8-K dated August 13, 2004 (File No. 007-11899) and incorporated by reference).
10.3	Form of Certificate of Designation of Series A Junior Participation Preferred Stock of The Houston Exploration Company (filed as exhibit 4.2 to our Current Report on Form 8-K dated August 13, 2004 (File No. 007-11899) and incorporated by reference).
10.4(*)	Form of waiver to employment agreement between The Houston Exploration Company and its executive officers allowing restricted stock awards in addition to stock option awards.
12.1(*)	Statement of computation of ratio of earnings to fixed charges.
31.1(*)	Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2(*)	Certification of 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, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
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

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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: November 4, 2004

William G. Hargett
Chairman, President and Chief Executive Officer

By: /s/ John H. Karnes

Date: November 4, 2004

John H. Karnes
Senior Vice President and Chief Financial Officer

By: /s/ James F. Westmoreland

Date: November 4, 2004

James F. Westmoreland
Vice President and Chief Accounting Officer

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Exhibit Index

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