HOUSTON EXPLORATION CO
Form 10-Q
May 09, 2007

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

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

For the quarterly period ended March 31, 2007

OR

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

For the transition period from __________ to __________.

Commission File No. 001-11899

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

Large accelerated filer þ Accelerated filer o Non-accelerated filer o

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

As of May 8, 2007, 23,302,579 shares of Common Stock, par value $0.01 per share, were outstanding.

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Forward-Looking Statements

Certain statements in this Quarterly Report on Form 10-Q (Quarterly Report) and the documents we have incorporated by reference into this Quarterly Report, other than purely historical information, including estimates, projections, statements relating to our business plans, strategies, objectives and expected operating results, and the assumptions upon which those statements are based, are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended (the Securities Act), and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act). These forward-looking statements generally may be identified by the words believe, project, expect, anticipate, estimate, intend, str plan, target, pursue, may, will, would, will continue, will likely result, and similar expressions. Forwar statements are based on current expectations and assumptions that are subject to numerous risks and uncertainties which may cause actual results to differ materially from the forward-looking statements. A detailed discussion of these and other risks and uncertainties that could cause actual results and events to differ materially from such forward-looking statements is included in Item 1A. Risk Factors of our Annual Report on Form 10-K for the year ended December 31, 2006, as amended, and in the joint proxy statement / prospectus dated May 1, 2007 related to our pending merger with Forest Oil Corporation, as well as Risk Factors set forth from time to time in our filings with the Securities and Exchange Commission (SEC). We undertake no obligation to update or revise publicly any forward-looking statements, whether as a result of new information, future events or otherwise.

Available Information

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, the joint proxy statement / prospectus dated May 1, 2007 relating to the pending merger with Forest and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are available free of charge on our Web site at http://www.houstonexploration.com as soon as reasonably practicable after we electronically file such material with, or otherwise furnish it to, the SEC.

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

In this Quarterly Report, unless the context requires otherwise, when we refer to we, us, our and Houston Exploratio we are describing The Houston Exploration Company and our subsidiaries, THEC, LLC and THEC, LP, on a consolidated basis. Also, unless the context requires otherwise, we are reporting historical results as of March 31, 2007 and December 31, 2006, and for the three-month periods ended March 31, 2007 and 2006.

If you are not familiar with the natural gas and oil terms used in this Quarterly Report, please refer to the explanations of the terms under the caption Glossary of Natural Gas and Oil Terms included on pages G-1 through G-2 of our Annual Report on Form 10-K for the year ended December 31, 2006, as amended. When we refer to equivalents, we are doing so to compare quantities of oil, condensate or natural gas liquids with quantities of natural gas or to express these different commodities in a common unit. In calculating equivalents, we use a generally recognized standard in which one barrel of oil, condensate or natural gas liquids is equal to six thousand cubic feet of natural gas. Unless otherwise stated, all reserve and production quantities are expressed net to our interests.

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

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

	March 31, 2007	December 31, 2006
Assets:		
Cash and cash equivalents	$ 29,487	$ 53,950
Accounts receivable	76,664	86,416
Derivative financial instruments	2,494	
Inventories	4,786	2,900
Deferred tax asset	19,811	10,244
Prepayments and other	5,506	8,370
Total current assets	138,748	161,880
Natural gas and oil properties, full cost method		
Unevaluated properties	34,880	28,317
Properties subject to amortization	3,605,097	3,478,878
Other property and equipment	15,211	15,101
	3,655,188	3,522,296
Less: Accumulated depreciation, depletion and amortization	1,988,032	1,930,964
	1,667,156	1,591,332
Other non-current assets	16,368	18,514
Total Assets	$ 1,822,272	$ 1,771,726
Liabilities:		
Accounts payable and accrued expenses	$ 144,190	$ 151,482
Derivative financial instruments	27,698	10,151
Total current liabilities	171,888	161,633
Long-term debt and notes	175,000	175,000
Derivative financial instruments	14,165	17,247
Deferred income taxes	377,912	363,322
Asset retirement obligations	77,314	72,782
Other non-current liabilities	21,243	17,138
Total Liabilities	837,522	807,122

Commitments and Contingencies (see Note 3)		
Stockholders Equity:		
Preferred Stock, $0.01 par value, 5,000,000 shares authorized and no shares issued		
Common Stock, $0.01 par value, 100,000,000 shares authorized and 28,231,771 and 28,098,172 shares issued and outstanding at March 31, 2007 and December 31, 2006, respectively	282	281
Additional paid-in capital	260,115	253,922
Retained earnings	740,765	731,150
Accumulated other comprehensive income (loss)	(16,412)	(20,749)
Total Stockholders Equity	984,750	964,604
Total Liabilities and Stockholders Equity	$ 1,822,272	$ 1,771,726

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

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

	Three Months Ended March 31,	
	2007	**2006**
Revenues:		
Natural gas and oil revenues	$ 103,623	$ 177,019
Other	208	585
Total revenues	103,831	177,604
Operating expenses:		
Lease operating	13,174	21,812
Severance tax	1,843	4,752
Transportation expense	2,362	2,771
Asset retirement accretion expense	1,082	1,327
Depreciation, depletion and amortization	57,089	83,761
General and administrative, net of amounts capitalized	10,145	8,606
Total operating expenses	85,695	123,029
Income from operations	18,136	54,575
Other (income) expense	(542)	
Interest expense, net of amounts capitalized	3,105	8,721
Income before income taxes	15,573	45,854
Provision for income taxes	5,628	16,082
Net income	$ 9,945	$ 29,772
Earnings per share:		
Net income per share basic	$ 0.36	$ 1.03
Net income per share diluted	$ 0.35	$ 1.02
Weighted average shares outstanding basic	27,945	29,042
Weighted average shares outstanding diluted	28,415	29,310

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

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

	Three Months Ended March 31,	
	2007	**2006**
Operating Activities:		
Net income	$ 9,945	$ 29,772
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	57,089	83,761
Deferred income tax expense	3,887	11,524
Asset retirement accretion expense	1,082	1,327
Stock compensation expense	2,421	2,517
Amortization of post retirement benefits	83	
Unrealized loss (gain) on derivative instruments	18,670	(4,586)
Changes in operating assets and liabilities:		
Accounts receivable	9,752	31,008
Inventories	(1,886)	(681)
Prepayments and other	2,864	5,409
Other non-current assets	2,146	1,304
Accounts payable and accrued expenses	(1,966)	(37,481)
Other non-current liabilities	2,465	(1,753)
Net cash provided by operating activities	106,552	122,121
Investing Activities:		
Investment in property and equipment	(134,789)	(128,391)
Deposit paid for property acquisition		(2,200)
Dispositions and other		189,371
Net cash (used in) provided by investing activities	(134,789)	58,780
Financing Activities:		
Proceeds from long-term borrowings		163,000
Repayments of long-term borrowings		(336,000)
Proceeds from issuance of common stock from exercise of stock options	3,402	3,213
Excess tax benefit from non-qualified stock options	372	445
Net cash provided by (used in) financing activities	3,774	(169,342)
(Decrease) increase in cash and cash equivalents	(24,463)	11,559
Cash and cash equivalents, beginning of period	53,950	7,979
Cash and cash equivalents, end of period	$ 29,487	$ 19,538

Supplemental Information:

Non-cash transactions:				
Change in investments in property and equipment accrued, not paid	$	5,326	$	7,444
Exchange of natural gas and oil producing properties and acreage		11,500		
Cash paid during period for:				
Interest	$	382	$	6,952
Federal and state income taxes paid (refunded)		(10,987)		

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

Overview of Our Business and Pending Merger

We are an independent natural gas and oil producer engaged in the exploration, development, exploitation and acquisition of natural gas and oil reserves in North America. We were founded in December 1985 as a Delaware corporation and completed our initial public offering in September 1996. Our operations are concentrated in four producing regions within the United States: South Texas; the Arkoma Basin; East Texas; and the Rocky Mountains.

On March 31, 2006, we completed the sale of the Texas portion of our Gulf of Mexico assets and on June 1, 2006, we completed the sale of substantially all of our Louisiana Gulf of Mexico assets (see Note 4 Acquisitions and Dispositions *Sale of Gulf of Mexico Assets 2006*). The sale of these offshore properties was part of our strategic plan announced in November 2005 to shift our operating focus primarily onshore. The sale of our Gulf of Mexico assets had a significant impact on our operating results for the year ended December 31, 2006 and on the comparability of our results for the first quarter of 2007 to the first quarter of 2006.

On January 7, 2007, we announced the conclusion to a strategic alternatives review process which began in June 2006 with our entry into an agreement and plan of merger with Forest Oil Corporation. Under the merger agreement, Forest will acquire all of the outstanding shares of Houston Exploration for a combination of cash and Forest common stock. Under the terms of the merger agreement, our shareholders will receive total consideration equal to 0.84 shares of Forest common stock and $26.25 in cash for each outstanding share of Houston Exploration common stock, or an aggregate of an estimated 23.8 million shares of Forest common stock and cash of $740 million. Based on the closing price of Forest common stock on January 5, 2007, the last trading day prior to announcement of the transaction, this represents $52.47 per share of merger consideration to be received by Houston Exploration shareholders. Based on the closing price of Forest common stock on April 30, 2007, the merger consideration would have a value of approximately $55.85 per share of Houston Exploration common stock. The actual value of the merger consideration to be received by our shareholders will depend on the average closing price of Forest common stock for the ten trading days ending three calendar days prior to the effective date of the merger, and the amount of cash and stock consideration will be determined by shareholder elections, subject to proration and an equalization formula. It is anticipated that the stock portion of the consideration will be tax free to Houston Exploration shareholders. Upon completion of the transaction, it is expected that Forest shareholders would own approximately 73% of the combined company, and Houston Exploration shareholders would own approximately 27%.

The Boards of Directors of Houston Exploration and Forest each unanimously approved the proposed merger. The merger is subject to customary terms and conditions, including the approval of stockholders of both Houston Exploration and Forest. Houston Exploration and Forest have scheduled special meetings of stockholders on June 5, 2007 to consider and vote on matters associated with the merger. Houston Exploration stockholders of record as of the close of business on April 30, 2007, the record date for its special meeting, are entitled to notice of, and to vote at, the special meeting. If the merger is approved by the stockholders of both Houston Exploration and Forest, closing of the merger is expected to occur in June 2007. Please read the definitive joint proxy statement / prospectus of Houston Exploration and Forest dated May 1, 2007.

Principles of Consolidation

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

Interim Financial Statements

Our balance sheet at March 31, 2007 and the statements of operations and cash flows for the periods indicated herein have been prepared without audit, pursuant to the rules and regulations of the SEC. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States (GAAP) have been condensed or omitted, although we believe that the disclosures contained herein are adequate to make the information presented not misleading. Our balance sheet at December 31, 2006 is derived from our December 31, 2006 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, 2006, as amended.

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

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

Use of Estimates

The preparation of the consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the dates of the financial statements, as well as the reported amounts of revenues and expenses during the reporting periods. Our most significant estimates are those based on remaining proved natural gas and oil reserves. Specifically, estimates of proved reserves are key components of our depletion rate for natural gas and oil properties and our full cost ceiling test limitation. In addition, estimates are used in determining taxes, accruals of operating costs and production revenues, asset retirement obligations, fair value and effectiveness of derivative instruments, fair value of stock options and stock-based compensation expense. Because there are numerous uncertainties inherent in the estimation process, actual results could differ materially from these estimates.

Reclassifications

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

Revenue Recognition and Gas Imbalances

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

We incur production gas volume imbalances in the ordinary course of business. Net deliveries in excess of entitled amounts are recorded as liabilities, 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 applicable.

At March 31, 2007, we had production imbalances representing assets of $0.8 million and liabilities of $4.5 million. At December 31, 2006, we had production imbalances representing assets of $2.8 million and liabilities of $2.4 million. Our receivables for production imbalances relate primarily to certain South Texas and Arkoma Basin properties and our payables relate primarily to certain Arkoma Basin properties. A significant portion of the Arkoma Basin imbalances were assumed in connection with our initial acquisition of these properties, and due to the inherent long life and comparatively low production rate of the wells, the imbalances will likely require a long period of time to resolve. Production imbalances are included in the line items other non-current assets and other non-current liabilities on our balance sheet.

Cash and Cash Equivalents

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

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

Net Income Per Share

Basic net income per share is calculated by dividing net income by the weighted average number of shares of common stock outstanding during the period. Diluted net income per share assumes the conversion of all potentially dilutive securities and is calculated by dividing net income by the sum of the weighted average number of shares of common stock outstanding plus all potentially dilutive securities. For us, potentially dilutive common shares consist primarily of stock options and restricted stock and restricted units.

	Three Months Ended March 31,	
	2007	**2006**
	(in thousands, except per share amounts)	
Numerator:		
Net income	$ 9,945	$ 29,772
Denominator:		
Weighted average shares outstanding	27,945	29,042
Add potentially dilutive securities: options and restricted stock/units	470	268
Total weighted average shares outstanding and dilutive securities	28,415	29,310
Earnings per share basic:	$ 0.36	$ 1.03
Earnings per share diluted:	$ 0.35	$ 1.02

For the three months ended March 31, 2007 and 2006, the calculation of shares outstanding for net income per share on a diluted basis does not include the effect of outstanding stock options to purchase 817,209 and 658,227 shares, respectively, because the exercise price for these shares was greater than the average market price for the respective periods, which would have an antidilutive effect on net income per share.

Comprehensive Income

Comprehensive income includes net income and certain items that are 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 (loss) for the three-month periods ended March 31, 2007 and 2006.

	Three Months Ended March 31,	
	2007	**2006**
	(in thousands)	
Net income	$ 9,945	$ 29,772
Other comprehensive income		
Derivative instruments settled and reclassified, net of tax	4,284	170,288
Future post retirement benefit obligation, net of tax	53	
Total other comprehensive income	4,337	170,288

Comprehensive income	$ 14,282	$ 200,060

Natural Gas and Oil Properties

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

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

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

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

unevaluated properties and their related costs; less,

estimates for salvage.

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

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

The ceiling test is calculated using natural gas and oil prices in effect as of the balance sheet date, as adjusted for basis or location differentials as of the balance sheet date and held constant over the life of the reserves (net wellhead prices). If applicable, these net wellhead prices would be further adjusted to include the effects of any fixed price arrangements for the sale of natural gas and oil. Historically, we have used derivative financial instruments to hedge against the volatility of natural gas prices. If our derivative contracts qualify and if they are designated as cash flow hedges under SFAS 133, Accounting for Derivative Instruments and Hedging Activities, then in accordance with SEC guidelines, we would include estimated future cash flows from our hedging program in our ceiling test calculation. Since our derivative contracts ceased to qualify as cash flow hedges during the first quarter of 2006, and since mark-to-market accounting is being applied to all of our open derivative contracts, including those contracts entered into during the first quarter of 2007, our ceiling test calculation at March 31, 2007 did not include the future cash flows from our hedging program. In addition, subsequent to the adoption of SFAS 143, Accounting for Asset Retirement Obligations, the future cash outflows associated with settling asset retirement obligations (ARO) are excluded from the computation of the discounted present value of future net revenues for the purposes of the ceiling test calculation.

In calculating our ceiling test at March 31, 2007, we estimated that, using an average net wellhead price of $6.09 per Mcf, the carrying value of our full cost pool exceeded the ceiling limitation by approximately $163.4 million ($104.4 million net of tax). However, since March 31, 2007 and prior to filing this Quarterly Report, the market price for natural gas increased such that, using an average net wellhead price of $6.73 per Mcf on May 1, 2007, no writedown was required.

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

We assess all items classified as unevaluated property on a quarterly basis for possible impairment or reduction in value. We assess our properties on an individual basis or as a group if properties are individually insignificant. Our assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the

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

cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization. We estimate that substantially all of our costs classified as unevaluated as of the balance sheet date will be evaluated and transferred within a four-year period.

Asset Retirement Obligations

The following table summarizes changes in our ARO liability during each of the three-month periods ended March 31, 2007 and 2006. The ARO liability in the table below includes amounts classified as both current and long-term at the end of the respective periods.

	Three Months Ended March 31,	
	2007	2006
	(in thousands)	
ARO liability at January 1,	$ 72,782	$ 119,671
Accretion expense	1,082	1,327
Liabilities incurred drilling	2,110	1,849
Liabilities incurred assets acquired	1,722	
Liabilities settled assets exchanged/sold	(376)	(30,795)
Changes in estimates	(6)	(76)
ARO liability at March 31,	$ 77,314	$ 91,976

Derivative Instruments and Hedging Activities

We account for derivative instruments utilizing Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) 133, Accounting for Derivative Instruments and Hedging Activities, as amended. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we have historically utilized derivative instruments to hedge future sales prices on a significant portion of our natural gas production. Our derivative instruments are not held for trading purposes. Our hedging policy allows us to implement a wide variety of hedging strategies, including swaps, collars and options. We generally execute derivative contracts with large, creditworthy financial institutions. Although our hedging program is intended to protect a portion of our cash flows from downward price movements, certain hedging strategies, specifically the use of swaps and collars, may also limit our ability to realize the full benefit of future price increases. In addition, because our derivative instruments are typically indexed to the New York Mercantile Exchange (NYMEX) price, as opposed to the index price where the gas is actually sold, our hedging strategy may not fully protect our cash flows when there are significant price differentials between the NYMEX price and index price at the point of sale.

At of March 31, 2007, we had entered into natural gas derivative contracts with respect to approximately 46% of our total forecasted production for the remaining nine months of 2007 and approximately 13% of our total forecasted production for 2008. The total estimated fair value of our open natural gas derivative instruments at March 31, 2007 and December 31, 2006 was a liability of $39.4 million and $27.4 million, respectively.

During the first quarter of 2006, our open derivative contracts ceased to qualify for hedge accounting due to a combination of factors, including the loss of correlation with the NYMEX price for certain contracts caused in part by the residual effects of Hurricanes Katrina and Rita during the first three months of 2006 and our entry into a definitive purchase and sale agreement to sell the Texas portion of our Gulf of Mexico assets in February 2006. At March 31, 2007, a net unrealized loss of $14.2 million, net of tax, relating to natural gas derivative contracts remains deferred in accumulated other comprehensive income. This loss represents the fixed value of our remaining open derivative contracts deferred in accumulated other comprehensive income at the time they ceased to qualify for hedge accounting. Over the next 12-month period and at the time when sale of the related natural gas production occurs, we expect to reclassify from accumulated other comprehensive income to earnings a net loss of $9.6 million, net of tax, leaving $4.6 million to be recognized during the remainder of 2008.

During the first three months of 2007, our total loss from hedging activities was $18.7 million, which included a realized loss of approximately $0.1 million on contracts settled during the period and a net unrealized loss of $18.6 million as a result of the change in the fair market value of open contracts, which includes $6.7 million in losses previously fixed and deferred in accumulated other comprehensive income at the time they ceased to qualify for hedge accounting.

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

Stock-Based Compensation

We account for stock-based compensation in accordance with the fair value recognition provisions of SFAS 123(R), Share-Based Payment. Under the fair value recognition provisions of SFAS 123(R), stock-based compensation costs are measured at the grant date based on the value of the award and recognized as expense over the vesting period. The following table summarizes stock compensation expense incurred during each of the three-month periods ended March 31, 2007 and 2006:

	Three Months Ended March 31,	
	2007	2006
	(in thousands)	
Options	$ 1,585	$ 1,687
Restricted stock/units	836	830
Stock compensation expense, gross	2,421	2,517
Amounts capitalized	(665)	(746)
Stock compensation expense, net of amounts capitalized	$ 1,756	$ 1,771

Amounts capitalized are categorized as leasehold costs and included as a component of our natural gas and oil property balance or full cost pool. Amounts expensed are included as a component of general and administrative expense. At March 31, 2007, our unrecognized stock compensation expense related to unvested stock options and expected to be recognized over a weighted average one and one half-year period was approximately $6.4 million. At March 31, 2007, our unrecognized compensation expense related to restricted stock and units and expected to be recognized over a weighted average one and one half-year period totaled $7.5 million. These amounts are classified as unearned compensation and included as a component of additional paid-in capital.

The total intrinsic value of options exercised during the three-month periods ended March 31, 2007 and 2006 was $2.7 million and $1.8 million, respectively.

Prior to the effective time of the pending merger with Forest and not more than six business days prior to June 5, 2007, the date of the special meeting of stockholders (see Consolidated Financial Statements, Note 5 Subsequent Events *Pending Merger with Forest Oil Corporation*), all outstanding stock options will vest and become fully exercisable, the restrictions on all outstanding shares of restricted stock will lapse, at which time these shares will become freely transferable, and all restricted units will become fully vested and the underlying shares of our common stock will be issued to the holder. All options with an exercise price per share that is less than the per share merger consideration, referred to as in-the-money options, not exercised prior to the effective time of the merger will be cancelled and cashed-out based on a formula provided for in the merger agreement, and all out-of-the money options not exercised prior to the effective time of the merger will be cancelled. We expect that all of our stock plans will be terminated as of the effective time of the merger.

Income Taxes

We adopted FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement 109 (FIN 48) as of January 1, 2007. FIN 48 clarifies the accounting for uncertainty in tax positions taken or expected to be taken in a tax return, including issues relating to financial statement recognition and measurement. Our adoption of FIN 48 did not have a material impact on our results of operations, financial position or liquidity. In connection with our adoption of FIN 48, we recorded a liability for unrecognized tax benefits of approximately $1.3 million, which primarily relates to timing differences associated with our deferred tax balances. In addition, we decreased the January 1, 2007 retained earnings balance by $0.3 million for the cumulative effect of the change in accounting principle related to our unrecognized tax benefits, which would favorably impact the effective income tax rate in future periods, if recognized. There was no material change to the uncertain tax benefits during the three months ended March 31, 2007.

Penalties and interest related to uncertain tax positions are recognized as a component of income tax expense. As of March 31, 2007, we have approximately $0.3 million of accrued interest related to uncertain tax positions, which was recorded in connection with the adoption of FIN 48. Our federal income tax return for the 2004 tax year is currently under examination by the Internal Revenue Service. No adjustments have been proposed as of the current date, and we do not anticipate a significant change in the amount of

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uncertain tax benefits during the next twelve months. The tax years 2003 2006 remain open to examination by the relevant taxing authorities. In addition, approximately $73.3 million of our net operating losses generated prior to 2003 may be subject to adjustment by the taxing authorities.

Recent Accounting Pronouncements

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. SFAS 157 defines fair value, establishes a framework for measuring fair value and requires enhanced disclosures regarding fair value measurements. SFAS 157 does not add any new fair value measurements, but it does change current practice and is intended to increase consistency and comparability of such measurements. The provisions of SFAS 157 are effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. Any amounts recognized upon adoption as a cumulative effect adjustment will be recorded to the opening balance of retained earnings in the year of adoption. We are currently evaluating the impact of adopting SFAS 157 on our financial statements and do not expect the interpretation will have a material impact on our results of operations or financial position.

In February 2007, FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities including an amendment of SFAS 115. SFAS 159 permits an entity to make an irrevocable election to measure most financial assets and financial liabilities at fair value. The fair value option may be elected on an instrument-by-instrument basis, with certain exceptions, as long as it is applied to the instrument in its entirety. Changes in fair value would be recorded in income. SFAS 159 establishes presentation and disclosure requirements intended to help financial statement users understand the effect of the entity s election on earnings. SFAS 159 is effective as of the beginning of the first fiscal year beginning after November 15, 2007 and interim periods within those fiscal years. We are currently evaluating the impact of adopting SFAS 159 on our financial statements and do not expect the interpretation will have a material impact on our results of operations or financial position.

NOTE 2 Long-Term Debt and Notes

	March 31, 2007	December 31, 2006
	(in thousands)	
Senior Debt:		
Revolving credit facility, due November 30, 2010	$	$
Subordinated Debt:		
7% senior subordinated notes, due June 15, 2013	175,000	175,000
Total long-term debt and notes	$ 175,000	$ 175,000

At March 31, 2007, the quoted market value of our $175 million of 7% senior subordinated notes was 100.25% of the $175 million carrying value, or $175.4 million. At December 31, 2006, the quoted market value of our $175 million of 7% senior subordinated notes was 98.5% of the $175 million carrying value, or $172.4 million.

Revolving Credit Facility

We maintain a revolving credit facility with a syndicate of lenders led by Wachovia Bank, National Association, as issuing bank and administrative agent, The Bank of Nova Scotia and Bank of America as co-syndication agents and BNP Paribas and Comerica Bank as co-documentation agents. The facility provides us with a commitment of $750 million, which may be increased at our request and with prior approval from the required lenders to a maximum of $850 million. Amounts available for borrowing under the credit facility are limited to a borrowing base that is redetermined semi-annually on April 1st and October 1st. Up to $60 million of our borrowing base is available for the issuance of letters of credit. As of March 31, 2007, our borrowing base was $500 million. Effective April 1, 2007, our current $500 million borrowing base was reaffirmed until the next scheduled semi-annual redetermination on

October 1, 2007. Outstanding borrowings under the revolving credit facility are secured by substantially all of our natural gas and oil assets as well as certain other assets and rank senior in right of payment to our $175 million of 7% senior subordinated notes. The facility matures on November 30, 2010. At March 31, 2007, we had no outstanding borrowings under the credit facility and $0.3 million in outstanding letter of credit obligations. Although we had no outstanding indebtedness under our bank credit facility as of March 31, 2007 or as of the date of this Quarterly Report, consummation of the pending merger with Forest will require the refinancing or repayment of any outstanding indebtedness thereunder.

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Our revolving credit facility contains customary financial and other covenants that place restrictions and limits on, among other things, the incurrence of debt, guarantees, liens, leases and certain investments. The credit facility also restricts and limits our ability to pay cash dividends, purchase or redeem our stock, and sell or encumber our assets. At March 31, 2007 and December 31, 2006, 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. We may redeem the notes at our option, in whole or in part, at any time on or after June 15, 2008, at a price equal to 100% of the principal amount plus accrued and unpaid interest, if any, plus a specified premium that decreases yearly from 3.5% in 2008 to 0% in 2011 and thereafter. The notes are general unsecured obligations and rank subordinate in right of payment to all of our existing and future senior debt, including the revolving bank credit facility, and will rank senior or equal in right of payment to all of our existing and future subordinated indebtedness.

The indenture governing the notes contains customary financial and other covenants that place restrictions and limits on, among other things, the incurrence of additional indebtedness, repayment of certain other indebtedness, guarantees, liens, and certain investments. The indenture also restricts and limits our ability to pay dividends or make certain other distributions, repurchase our stock, and sell or encumber our assets. In addition, upon the occurrence of a change of control (as defined in the indenture and including our pending merger with Forest), the obligor or successor obligor on the notes will be required to offer to purchase the notes at a purchase price equal to 101% of the aggregate principal amount, plus accrued and unpaid interest and liquidated damages, if any. At March 31, 2007 and December 31, 2006, we were in compliance with all covenants under the indenture governing the notes.

At the request of Forest, and in connection with the pending merger, we commenced a tender offer and consent solicitation to repurchase any or all of the notes immediately prior to the completion of the merger. See Consolidated Financial Statements, Note 5 Subsequent Events *Tender Offer and Consent Solicitation for $175 Million of 7% Senior Subordinated Notes due 2013*.

NOTE 3 Commitments and Contingencies

Legal Proceedings

On June 22, 2006, the City of Monroe Employees Retirement System filed a purported class action lawsuit in the District Court of Harris County, Texas, on behalf of itself and all of the company s other public shareholders, against the company and its directors. The plaintiff alleges that the defendants breached their fiduciary duties of loyalty and due care to the class in connection with our response to an unsolicited proposal by JANA Partners LLC to purchase the company. The plaintiff subsequently amended its petition as a derivative claim and requested that the court order the defendants to comply with their fiduciary duties, respond in good faith to potential offers, and establish a committee of independent directors to evaluate strategic alternatives and take decisive steps to maximize shareholder value. The plaintiff also seeks to invalidate our shareholder rights plan or require the defendants to rescind or redeem such plan. Finally, the plaintiff seeks compensatory and punitive damages, as well as attorneys and experts fees. In October 2006, the judge denied the defendants motion to abate or special exceptions. Although this ruling allows the plaintiff s claim to survive beyond the pleadings stage, it has no bearing on the merits of the case. In January 2007 and following our entry into the merger agreement with Forest, the plaintiff further amended its petition, adding a new class-action claim challenging the strategic alternatives review process conducted by us and the adequacy of the merger consideration agreed upon in the merger agreement, and naming Forest as a defendant. The plaintiff also seeks to enjoin the merger, asserting that our directors decision to enter into the merger with Forest constitutes a breach of fiduciary duties. We believe this lawsuit is without merit, and we intend to vigorously defend against it. Although it is too soon to predict the outcome of this lawsuit or the time to resolution, we do not believe that it will have a material adverse effect on our financial position, results of operations or cash flows.

In 2004, we filed a lawsuit and initiated an arbitration proceeding against several parties related to a builder s risk insurance policy and insurance claims associated with the installation and repair of certain facilities at the South

Timbalier Block 317A offshore platform. Our claims include (i) breach of the insurance contract for denial of coverage; (ii) alternatively, if there is no coverage, failure to procure an insurance policy providing the coverage; (iii) conversion and fraud associated with the overcharge of insurance premiums; and (iv) violations of the Texas Insurance Code. The underwriters and the

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insurance broker filed counterclaims against us seeking attorneys fees, alleging that our claims under the Texas Insurance Code were groundless or brought in bad faith or for the purpose of harassment. In June 2006, the court granted our motion for summary judgment on one of the principal issues in the lawsuit, finding that our claims for standby expenses arising out of repairs to the platform were covered by the policy. In September 2006, the Underwriters amended their counterclaim against us, alleging fraud and breach of the insurance contract regarding the manner in which the claims were presented. The underwriters seek to have the insurance policy declared void and to recover approximately $2.2 million paid under the policy, plus punitive damages, costs and attorneys fees. In October 2006, the insurance broker amended its counterclaim, seeking unspecified damages for libel on the grounds that we acted with malice and knowledge of falsity in reporting his alleged mishandling of settlement funds to the Texas Insurance Commission. Substantial discovery has occurred. The arbitration is currently in abeyance pending the outcome of the litigation, and the lawsuit is currently set for trial in July 2007. We believe the counterclaims are without merit, and we are vigorously defending the allegations against us and continuing to pursue our claims against the defendants. At this time, management cannot reasonably estimate whether a loss may be incurred with respect to this matter or the amount or range of any potential loss; however, we do not believe that our liability, if any, associated with this matter will have a material adverse effect on our financial position, results of operations or cash flows.

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

Severance Tax Refund

During July 2002, we applied for and received from the Railroad Commission of Texas a high-cost/tight-gas formation designation for a portion of our South Texas production. For qualifying wells, production is either exempt from tax or taxed at a reduced rate until certain capital costs are recovered. For the three months ended March 31, 2007 and 2006, we recognized as reductions to severance tax expense refunds of prior period severance tax payments of $3.4 million and $1.4 million, respectively. At March 31, 2007 and December 31, 2006, our current receivables include $5.7 million and $2.0 million, respectively, in gross refunds, of which we estimate approximately 70%, or $4.0 million and $1.4 million, respectively, relate to our net revenue interest. Beginning September 1, 2003, all refunds issued by the State of Texas are to be made in the form of a reduction to or credit against our current severance tax liability rather than in the form of a cash reimbursement.

Operating Leases

We have entered into non-cancelable operating lease agreements in the ordinary course of our business activities. These leases include those for our office space at 1100 Louisiana Street in Houston, Texas, and at 700 17th Street in Denver, Colorado, together with various types of office equipment (such as copiers and fax machines). The terms of these agreements have various expiration dates from 2007 through 2010. Future minimum lease payments for the remainder of 2007 and each of the subsequent three years from 2008 through 2010 are $1.4 million, $1.9 million, $1.1 million and less than $0.1 million, respectively.

Letters of Credit

We had $0.3 million in letters of credit outstanding at each of March 31, 2007 and December 31, 2006.

Drilling Contracts

At of March 31, 2007, we had one drilling rig located in East Texas under a long-term contract. Under this contract we are obligated for up to an estimated $5.3 million in fees for the use of the rig until expiration of the contract in February 2008.

Postretirement Benefit Obligation

We maintain a Supplemental Executive Retirement Plan (SERP) to provide retirement benefits to certain management level or other highly compensated employees. Our SERP is an unfunded, non-tax qualified defined benefit pension plan, with participation currently limited to only our executive officers. Participants in the SERP will be entitled to a monthly retirement benefit payable for life. At March 31, 2007 and December 31, 2006, our total unfunded benefit obligation was a liability of $5.3 million and $5.1 million, respectively, and we had prior service costs and net actuarial losses, net of tax, of

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$2.2 million for each respective period-end, deferred as a component of accumulated other comprehensive income. Assuming the termination of employment of each of our executive officers as of June 30, 2007 following the merger with Forest, the total lump sum that would be payable under the SERP is estimated to be approximately $3.2 million. Pursuant to the terms of the merger agreement, Forest will assume this payment obligation under our SERP as of the effective time of the merger.

NOTE 4 Acquisitions and Dispositions

Property Exchange 2007

On March 9, 2007, we completed a non-cash producing property exchange with Questar Exploration and Production Company. The properties exchanged had an agreed upon fair value of approximately $11.5 million as of the January 1, 2007 effective date of the exchange. In connection with the exchange transaction, we transferred to Questar 58 producing wells with an average working interest of 16% and net proved reserves of 4.6 Bcfe as of January 1, 2007, covering approximately 15,600 gross (4,000 net) developed and undeveloped acres located in primarily the Wilburton and South Panola Fields of Latimer County, Oklahoma. Questar transferred to us 31 producing wells with an average working interest of 83% and net proved reserves of 10.4 Bcfe as of January 1, 2007, covering approximately 4,100 gross (3,400 net) developed and undeveloped acres primarily located in the Willow Springs Field of Gregg County, Texas where we have existing operations. In accordance with full cost accounting, no book gain or loss was recognized on the exchange transaction.

Sale of Gulf of Mexico Assets 2006

On March 31, 2006, we completed the sale of the Texas portion of our Gulf of Mexico assets. Pursuant to the purchase and sale agreement dated February 28, 2006 between us, as seller, and various partnerships affiliated with Merit Energy Company, as buyer, the gross sale price was $220 million. The net cash proceeds received from the sale of these assets totaled approximately $190.8 million after various customary closing items, including the adjustment for operations related to the properties after January 1, 2006, the effective date of the transactions. Of the total net proceeds, approximately $140.1 million was received for assets acquired by various partnerships affiliated with Merit Energy Company. In addition, approximately $43.1 million and $7.6 million were received from Hydro Gulf of Mexico, L.L.C. and Nippon Oil Exploration U.S.A. Ltd., respectively, pursuant to the exercise of their preferential rights to acquire certain working interests offered for sale. The Texas portion of our Gulf of Mexico assets accounted for approximately 18% of our 2005 production and represented an estimated 58.5 Bcfe, or 7% of our total proved reserves at December 31, 2005. Of the $190.8 million in net cash proceeds received from the sale of our Texas Gulf of Mexico assets, we used $158 million to repay and reduce outstanding borrowings under our revolving credit facility, deposited $9.5 million with a qualified intermediary for potential reinvestment in like-kind exchange transactions under Section 1031 of the Internal Revenue Code, and used substantially all of the $23.3 million balance for working capital purposes. In accordance with full cost accounting, no gain or loss was recognized on the sale. The net proceeds of $190.8 million were recorded as a reduction to the full cost pool.

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

At December 31, 2005, proved reserves associated with these assets were estimated at 186.1 Bcfe, and production associated with these assets accounted for approximately 22% of our 2005 production and 27% of our production during the first six months of 2006. The sale transactions did not include 18 Louisiana offshore blocks retained by us. Of these 18 blocks, eight expired subsequent to the sales transactions, two were drilled during 2006, resulting in two successful exploratory wells, and eight remain classified as undeveloped at the end of the first quarter of 2007.

Of the $530.8 million in net cash proceeds received from the sale of the Louisiana portion of our Gulf of Mexico assets, $314.2 million was deposited directly with qualified intermediaries for potential reinvestment in like-kind exchange

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transactions under Section 1031 of the Internal Revenue Code, and substantially all of the $216.6 million balance, associated with properties sold outside the like-kind exchange arrangement, was used to reduce outstanding borrowings under our revolving credit facility. In accordance with full cost accounting, no gain or loss was recognized on the sale. The net proceeds of $530.8 million were recorded as a reduction to the full cost pool.

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

NOTE 5 Subsequent Events

Pending Merger Agreement with Forest Oil Corporation

Houston Exploration and Forest have scheduled special meetings of stockholders on June 5, 2007 to consider and vote on matters associated with the merger. Houston Exploration stockholders of record as of the close of business on April 30, 2007, the record date for the special meeting, are entitled to notice of, and to vote at, the special meeting. Please read the definitive joint proxy statement / prospectus of Houston Exploration and Forest dated May 1, 2007.

Tender Offer and Consent Solicitation for $175 Million of 7% Senior Subordinated Notes due 2013

On May 2 2007, we commenced a cash tender offer for any or all of our outstanding $175 million aggregate principal amount of 7% senior subordinated notes due 2013 on the terms and subject to the conditions set forth in our offer to purchase and consent solicitation statement dated May 2, 2007. In connection with the offer to repurchase, we are also soliciting consents for proposed amendments to the indenture under which the notes were issued that would eliminate most of the restrictive covenants and events of default contained in the indenture. The first supplemental indenture will not be executed unless and until we have received consents from holders of a majority of the outstanding principal amount of the notes, and the amendments will not become operative unless and until we have accepted the notes for purchase pursuant to the offer to purchase. Holders who consent to the proposed amendments will be required to tender their notes.

Consummation of the offer is subject to the satisfaction or waiver of a number of conditions set forth in the offer to purchase, including the satisfaction or waiver of all conditions to completion of our pending merger with Forest and execution of the first supplemental indenture. The offer to purchase will expire at 5:00 p.m. Eastern time on June 5, 2007, unless extended or terminated by us. The consent solicitation will expire at 5:00 p.m. Eastern time on May 21, 2007, unless extended.

The consideration to be paid by us for each $1,000 principal amount of notes tendered and accepted for payment is $1,010.00, plus accrued and unpaid interest. In addition, a consent payment in the amount of $2.50 per $1,000 principal amount of notes will be paid to those holders who consent to the proposed amendments prior to the consent deadline. We expect to pay the total consideration of $1,012.50, plus accrued and unpaid interest, to consenting holders promptly following both the expiration time and the satisfaction or waiver of the conditions to closing of the offer. Assuming all of the holders validly tender their notes and deliver their consents, the aggregate consideration to be paid by us in connection with the tender offer and consent solicitation, including the payment of the accrued interest and all related fees and expenses, will be approximately $183.0 million. We expect to fund this payment with cash on hand and borrowings under our revolving credit facility. In the event the merger is not consummated, Forest has agreed to reimburse us for all expenses and indemnify us against certain liabilities associated with the repurchase.

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

The following discussion is intended to assist you in understanding our business and results of operations, together with our present financial condition. This section should be read in conjunction with our Consolidated Financial Statements and the accompanying notes included elsewhere in this Quarterly Report on Form 10-Q, as well as our Annual Report on Form 10-K, as amended, for the year ended December 31, 2006.

Statements in our discussion may be forward-looking. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause actual results, including future production, revenues and expenses, to differ materially from our expectations. See Forward-Looking Statements at the beginning of this Quarterly Report, Item 1A. Risk Factors in our Annual Report on Form 10-K, as amended, for the year ended December 31, 2006, and the joint proxy statement / prospectus dated May 1, 2007 relating to our pending merger with Forest for additional discussion of risks affecting our business.

Overview of Our Business

We are an independent natural gas and oil producer engaged in the exploration, development, exploitation and acquisition of natural gas and oil reserves in North America. We were founded in December 1985 as a Delaware corporation and completed our initial public offering in September 1996. Our operations are concentrated in four producing regions within the United States: South Texas; the Arkoma Basin; East Texas; and the Rocky Mountains. On March 31, 2006, we completed the sale of the Texas portion of our Gulf of Mexico assets and on June 1, 2006, we completed the sale of substantially all of our Louisiana Gulf of Mexico assets. The sale of these offshore properties was part of our strategic plan announced in November 2005 to shift our operating focus primarily onshore. The sale of our Gulf of Mexico assets had a significant impact on our operating results for the year ended December 31, 2006 and on the comparability of our results for the first quarter of 2007 to the first quarter of 2006.

Our total net proved reserves as of December 31, 2006 were 699 Bcfe. All of our reserves are estimated on an annual basis by independent petroleum engineers. Approximately 96% of our proved reserves at December 31, 2006 were natural gas and approximately 67% were classified as proved developed.

We derive our revenues from the sale of natural gas and oil produced from our natural gas and oil properties. Revenues are a function of the volume produced and the prevailing market price at the time of sale. Because natural gas accounts for approximately 92% of our production, the price of natural gas is the primary factor affecting our revenues. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we have historically utilized derivative instruments to hedge future sales prices on a significant portion of our natural gas production. Our use of derivative instruments prevented us from realizing the full benefit of the strong natural gas price environment during each of the preceding four years, and may continue to do so in 2007 and in future periods. Our natural gas revenues may experience significant volatility in future periods as all of our open derivative contracts ceased to qualify for hedge accounting during the first quarter of 2006. See Consolidated Financial Statements, Note 1 Summary of Organization and Significant Accounting Policies *Derivative Instruments and Hedging Activities*.

Segment reporting is not applicable for us, as all of our assets are located in North America, and each of our operating areas has similar economic characteristics and each meets the criteria for aggregation as defined in SFAS 131, Disclosures about Segments of an Enterprise and Related Information.

Pending Merger with Forest Oil Corporation

On January 7, 2007, we announced the conclusion to the strategic alternatives review process begun in June 2006 with our entry into an agreement and plan of merger with Forest. Under the merger agreement, Forest will acquire all of the outstanding shares of Houston Exploration for a combination of cash and Forest common stock.

Under the terms of the merger agreement, our shareholders will receive total consideration equal to 0.84 shares of Forest common stock and $26.25 in cash for each outstanding share of Houston Exploration common stock, or an aggregate of an estimated 23.8 million shares of Forest common stock and cash of approximately $740 million. Based on the closing price of Forest common stock on January 5, 2007, the last trading day prior to announcement of the transaction, this represents $52.47 per share of merger consideration to be received by Houston Exploration shareholders. Based on the closing price of Forest common stock on April 30, 2007, the merger consideration would have a value of approximately $55.85 per share of Houston Exploration common stock. The actual value of the merger consideration to be received by our shareholders will depend on the average closing price of Forest common stock for the ten trading days ending three calendar days prior to the effective date of the merger, and the amount of cash and stock consideration will be determined by shareholder elections, subject to proration and an equalization formula. It is anticipated that the stock portion of the consideration will be tax free to Houston Exploration shareholders.

The Boards of Directors of Houston Exploration and Forest each unanimously approved the proposed merger. The merger is subject to customary terms and conditions, including the approval of stockholders of both Houston Exploration and Forest, and is expected to be completed in June 2007. Upon completion of the transaction, it is anticipated that Forest shareholders would own approximately 73% of the combined company, and Houston Exploration shareholders would own approximately 27%.

Houston Exploration and Forest have scheduled special meetings of stockholders on June 5, 2007 to consider and vote on matters associated with the merger. Houston Exploration stockholders of record as of the close of business on April 30, 2007, the record date for its special meeting, are entitled to notice of, and to vote at, the special meeting. Please read the definitive joint proxy statement / prospectus of Houston Exploration and Forest dated May 1, 2007.

Critical Accounting Estimates and Significant Accounting Policies

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of our financial statements requires us to make assumptions and prepare estimates that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities and revenues and expenses. We base our estimates on historical experience and various other assumptions that we believe are reasonable; however, actual results may differ. We evaluate our assumptions and estimates on a regular basis and discuss the development and disclosure process with our Audit Committee. Estimates of proved reserves are key components of our most significant financial estimates involving depreciation, depletion and amortization and our full cost ceiling limitation. In addition, estimates are used to accrue production revenues and operating expenses, drilling costs, federal and state taxes, the fair value of derivative contracts, including the calculation of ineffectiveness, and the fair value of our stock options. There has been no change in our critical accounting policies and use of estimates since our Annual Report for the year ended December 31, 2006, as amended.

Recent Accounting Pronouncements

See Consolidated Financial Statements, Note 1 Summary of Organization and Significant Accounting Policies *Recent Accounting Pronouncements* for discussions of SFAS 157, Fair Value Measurements and SFAS 159, The Fair Value Option for Financial Assets and Financial Liabilities including an amendment of SFAS 115. We are currently evaluating the impact of adopting SFAS 157 and SFAS 159 on our financial statements and do not expect the interpretation will have a material impact on our results of operations or financial position.

Overview of Results for the First Quarter of 2007

The comparability of our operating and financial results for the first three months of 2007 to the first three months of 2006 was significantly impacted by the sale of substantially all of our Gulf of Mexico assets during the first half of 2006 (see Note 4 Acquisitions and Dispositions *Sale of Gulf of Mexico Assets 2006*). Our operating results for the first three months of 2006 include production, revenues and expenses relating to our Texas Gulf of Mexico properties until the completion of their sale on March 31, 2006 and our Louisiana Gulf of Mexico properties until the completion of their sale on June 1, 2006. Reserves, production volumes, revenues, operating expenses and cash flows were all lower quarter-over-quarter and are expected to remain lower unless reserves and production from the properties sold are replaced in full.

With the shift in focus to onshore operations during 2006 and the resulting expansion of our onshore capital exploration and development drilling program, production from our onshore assets increased 7% for the first quarter of 2007 as compared to the first quarter of 2006. However, natural gas and oil revenues generated from onshore assets were 10% lower quarter-over-quarter, primarily as a result of average unhedged natural gas prices that were 16% lower during the first quarter of 2007 as compared to the first quarter of 2006, offset in part by an increase in oil revenues generated from an increase in South Texas oil and natural gas liquids production. As a result of the decline in natural gas prices, combined with a significant decrease in the percentage of our production volume hedged quarter-over-quarter, our cash losses on derivative contracts settled during the period narrowed considerably from a loss of $46.5 million during the first quarter of 2006 to a loss of just under $0.1 million during the first quarter of 2007. Total operating expenses were 30% lower quarter-over-quarter as a direct result of the sale of substantially all of our Gulf of Mexico assets during the first half of 2006. These factors were the primary drivers behind results of operations, net income and cash flows during the first three months of 2007. During the first quarter of 2007:

- We entered into an agreement and plan of merger with Forest Oil Corporation on January 7, 2007. Under the merger agreement, Forest will acquire all of the outstanding shares of Houston Exploration for a combination of cash and Forest common stock (see Consolidated Financial Statements, Note 5 Subsequent Events *Pending Merger with Forest Oil Corporation*);

- We generated net income of $9.9 million, which included an unrealized loss of $18.7 million ($11.9 million after tax) resulting from the change in the fair market value of our open derivative contracts, compared to $29.8 million in net income during the first quarter of 2006, which included unrealized gains from hedging activities of $4.6 million ($3.0 million after tax), a decrease of 67% quarter-over-quarter;

- We produced approximately 19.5 Bcfe and our average total production rate was 216 MMcfe per day, a decrease of approximately 8.7 Bcfe and 96 MMcfe per day, respectively, from the first quarter of 2006. This decrease is primarily a result of the sale of substantially all of our offshore assets during the first half of 2006, offset in part by an increase in production from our onshore assets;

- We increased production from our onshore properties by 7%, to 216 MMcfe per day, from 202 MMcfe per day during the first quarter of 2006;

- We generated $106.6 million in cash flows from operating activities, a decrease of 13% from the $122.1 million generated during the first quarter of 2006;

- Using cash flow generated from operations and cash on-hand, we invested $129.3 million in natural gas and oil properties;

- We completed a non-cash, like-kind property exchange valued at $11.5 million, exchanging all our reserves, producing wells and acreage located in eastern Oklahoma for reserves, producing wells and acreage located primarily in the Willow Springs Field of East Texas (see Consolidated Financial Statements, Note 4 Acquisitions and Dispositions); and

We drilled 90 wells, of which 75, or 83%, were successful, including 40 in the Rockies, 14 in South Texas, 12 in Arkoma, and 9 in East Texas.

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Operating and Financial Results for the three months ended March 31, 2007 compared to the three months ended March 31, 2006.

The comparability of our operating and financial results for the first three months of 2007 to the first three months of 2006 was significantly impacted by the sale of substantially all of our Gulf of Mexico assets during the first half of 2006. Our operating results for the first three months of 2006 include production, revenues and expenses relating to our Texas Gulf of Mexico properties until the completion of their sale on March 31, 2006 and our Louisiana Gulf of Mexico properties until the completion of their sale on June 1, 2006.

	Three Months Ended March 31,			
Summary Operating Information:	**2007**	**2006**	**Change**	**%**
	(in thousands, except prices and percentages)			
Operating revenues	$103,831	$177,604	$(73,773)	-42%
Operating expenses	85,695	123,029	(37,334)	-30%
Income from operations	18,136	54,575	(36,439)	-67%
Net income	9,945	29,772	(19,827)	-67%
Production:				
Natural gas (MMcf)	17,809	26,023	(8,214)	-32%
Oil and natural gas liquids (MBbls)	274	348	(74)	-21%
Total (MMcfe)(1)	19,453	28,111	(8,658)	-31%
Average daily production (MMcfe/d)	216	312	(96)	-31%
Average Sales Prices:				
Natural Gas (per Mcf) unhedged	$ 6.24	$ 7.63	$ (1.39)	-18%
Natural Gas (per Mcf) realized(2)	6.23	5.84	0.39	7%
Natural Gas (per Mcf) all-in(3)	5.19	6.02	(0.83)	-14%
Oil and natural gas liquids (per Bbl) realized	$ 41.13	$ 58.77	$ (17.64)	-30%

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

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

(3) Includes gains and losses realized on derivative contracts settled during the period, as well as unrealized gains and losses recognized pursuant to SFAS 133, Accounting for Derivative Instruments and Hedging Activities.

Production Volume

	Three Months Ended March 31,			
	2007	**2006**	**Change**	**%**
	(in thousands, except percentages)			
Natural Gas (MMcf):				
Onshore	17,797	17,816	(19)	
Offshore	12	8,207	(8,195)	-100%
Total natural gas	17,809	26,023	(8,214)	-32%
Oil and Natural Gas Liquids (MBbls):				
Onshore	273	67	206	307%
Offshore	1	281	(280)	-100%
Total oil and natural gas liquids	274	348	(74)	-21%
Natural Gas Equivalent (MMcfe):				
Onshore	19,435	18,218	1,217	7%
Offshore	18	9,893	(9,875)	-100%
Total equivalents	19,453	28,111	(8,658)	31%

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

	Three Months Ended March 31,			
	2007	2006	Change	%
Natural Gas Equivalent (MMcfe per day):				
South Texas	151	145	6	4%
Arkoma	39	40	(1)	-3%
East Texas	15	11	4	36%
Rockies	11	6	5	83%
Total onshore	216	202	14	7%
Offshore		110	(110)	-100%
Total equivalents per day	216	312	(96)	-31%

Primarily as a result of the sale of substantially all of our Gulf of Mexico assets during the first half of 2006, our total production volumes were 31% lower during the first three months of 2007 compared to the first three months of 2006.

Onshore. During the first three months of 2007, average daily production from our onshore properties increased by 7% from the corresponding period of 2006. Quarter-over-quarter, natural gas production was essentially flat and oil and natural gas liquids production increased by over 300%, or 206 MBbls (1.2 Bcfe). In South Texas, production increased 4% quarter-over-quarter, due primarily to our successful developmental drilling program begun in April 2006 in the Rincon and Tijerina-Canales-Blucher Fields that were acquired in November 2005. New wells drilled in the Rincon and Tijerina-Blucher Fields were the primary source for the increase in natural gas liquids production. In Arkoma, average daily production was essentially flat, declining 1 MMcfe per day quarter-over-quarter, as the curtailments seen during the second half of 2006 continued as a result of oversupply in the gathering system. In East Texas, production increased by 4 MMcfe per day, or 36%, quarter-over-quarter, as a direct result of the successful expansion of our developmental drilling during 2006 on properties and acreage acquired during 2005 and 2006. In the Rockies, we continued to add production and connect completed wells to sales, as evidenced by our average daily production rates, which increased by 5 MMcfe per day, or 83%, quarter-over-quarter.

Offshore. For the first three months of 2007, offshore production was minimal and generated primarily from the interests we retained in our West Cameron 39 prospect that was in progress at the time of the sale transactions. For the first three months of 2006, offshore production is comprised of production from both our Texas and Louisiana Gulf of Mexico assets prior to the completion of their sale.

Commodity Prices and Effects of Hedging Activities

	Three Months Ended March 31,			
	2007	2006	Change	%
Average Natural Gas Prices ($ per Mcf):				
Onshore	$ 6.21	$ 7.35	$ (1.14)	-16%
Offshore		8.24	(8.24)	100%
Total Natural Gas unhedged	6.24	7.63	(1.39)	-18%
Total Natural Gas realized[1]	6.23	5.84	0.39	7%
Total Natural Gas all-in[2]	5.19	6.02	(0.83)	-14%

Average Oil and Natural Gas Liquids Prices ($ per Bbl):				
Onshore	$41.14	$56.63	$(15.49)	-27%
Offshore		59.28	(59.28)	-100%
Total Oil and Natural Gas Liquids	41.13	58.77	(17.64)	-30%

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

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

Commodity Prices and Effects of Hedging Activities. Our total average unhedged sales price for natural gas decreased by 18% from $7.63 per Mcf during the first three months of 2006 to $6.24 per Mcf during the first three months of 2007. Our cash losses from derivative contracts settled during the first quarter of 2007 were less than $0.1 million and as a result, we realized an average natural gas price of $6.23 per Mcf which was $0.01 per Mcf lower than, our average unhedged price of

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$6.24 per Mcf for the quarter and compares to an average realized price of $5.84 per Mcf during the first quarter of 2006 that was 77% of, or $1.79 per Mcf lower than, the total unhedged price of $7.63. Cash losses on derivative contracts improved significantly quarter-over-quarter from a loss of $46.5 million during the first quarter of 2006 to a loss of less than $0.1 million during the first three months of 2007. This improvement was due primarily to a reduction in the volume of natural gas hedged from approximately 83% hedged during the first quarter of 2006 to approximately 28% hedged during the first quarter of 2007, combined with lower NYMEX settlement prices for natural gas during the first quarter of 2007.

Gains (Losses) from Hedging Activities. The following table summarizes and compares the components of our realized and unrealized gains and losses due to derivative contracts and hedging activities for the three months ended March 31, 2007 and 2006. All of the non-cash, unrealized gains and losses shown in the table result from accounting for derivative instruments under SFAS 133.

During the first quarter of 2006, our open derivative contracts ceased to qualify for hedge accounting due to a combination of factors, including the loss of correlation with the NYMEX price for certain contracts caused in part by the residual effects of Hurricanes Katrina and Rita during the first three months of 2006 and our entry into a definitive purchase and sale agreement to sell the Texas portion of our Gulf of Mexico assets. As a result of the loss of hedge accounting, all open derivative contracts (including all new contracts entered into during 2007) were accounted for using mark-to-market accounting with subsequent changes in fair value accounted for as increases or decreases to natural gas and oil revenues. The use of mark-to-market accounting has caused volatility in our natural gas and oil revenues and is expected to continue to cause volatility during future periods. All amounts in the following table are shown on a pre-tax basis and are included in our statement of operations on the line item natural gas and oil revenues.

	Three Months Ended March 31,		
	2007	2006	Change
	(in thousands)		
Gain (Loss) from Hedging Activities			
Cash (loss) realized on contracts settled	$ (51)	$ (46,525)	$ 46,474
Non-cash unrealized gain (loss):			
Mark-to-market change in fair value gain (loss)(1)	(11,971)	38,166	(50,137)
Recognition of deferred gain (loss) on contracts fixed at time of loss of hedge accounting(2)	(6,699)	15,790	(22,489)
Recognition of deferred loss due to fourth quarter 2005 production shortfalls(3)		(20,600)	20,600
Recognition of all deferred losses relating to Texas Gulf of Mexico production sold(4)		(28,770)	28,770
Total non-cash unrealized gain (loss)	(18,670)	4,586	23,256
Total gain (loss) from hedging activities	$ (18,721)	$ (41,939)	$ 23,218

(1) Comprised of change in fair market value of open contracts subsequent to loss of hedge accounting, including all new contracts

entered into during the first quarter of 2007.

(2) Comprised of recognition of a portion of losses relating to open contracts that were fixed and deferred in accumulated other comprehensive income at the time all of our contracts ceased to qualify for hedge accounting. Over the next 12-month period and at the time when sale of the related natural gas production occurs, we expect to reclassify from accumulated other comprehensive income to earnings deferred losses totaling approximately $9.6 million, net of tax, leaving $4.6 million to be recognized during the remainder of 2008.

(3) For the first quarter of 2006, comprised of recognition of the loss related to cash

settlements made during the fourth quarter of 2005 that was deferred during the fourth quarter of 2005 in accumulated other comprehensive income. This deferred loss resulted from offshore production shortfalls during the fourth quarter of 2005 caused by Hurricanes Katrina and Rita.

(4) For the first quarter of 2006, comprised of recognition of all losses previously deferred in accumulated other comprehensive income for which the underlying production was attributable to Gulf of Mexico assets sold.

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Natural Gas and Oil Revenues

	Three Months Ended March 31,			
	2007	2006	Change	%
	(in thousands, except percentages)			
Natural Gas Revenues:				
Onshore	$ 110,571	$ 130,875	$ (20,304)	-16%
Offshore	503	67,630	(67,127)	-99%
Gain (loss) on settled derivatives	(51)	(46,525)	46,474	-100%
Unrealized gain (loss) on derivatives	(18,670)	4,586	(23,256)	-507%
Total natural gas revenues	92,353	156,566	(64,213)	-41%
Oil and Natural Gas Liquids Revenues:				
Onshore	11,230	3,794	7,436	196%
Offshore	40	16,659	(16,619)	-100%
Total oil and natural gas liquids revenues	11,270	20,453	(9,183)	-45%
Total natural gas and oil revenues	$ 103,623	$ 177,019	$ (73,396)	-41%

Natural Gas Revenues. For the first three months of 2007, natural gas revenues from our onshore properties declined by $20.3 million, or 16%, from levels during the corresponding first three months of 2006 due to average unhedged natural gas prices that were 16%, or $1.14 per Mcf, lower quarter-over-quarter, as onshore natural gas production remained flat quarter-over-quarter at approximately 17.8 Bcfe.

A significant reduction in the aggregate size of our hedge portfolio, combined with lower natural gas prices during the first quarter of 2007, significantly reduced our net loss on derivatives settled during the quarter by $46.5 million. As a result of the liquidation of a portion of our open derivative contracts in connection with and subsequent to the sale of our Gulf of Mexico assets, together with the expiration of a large portion of our open contracts at December 31, 2006, we had derivative contracts covering approximately 28% of our natural gas production during the first quarter of 2007 compared to derivative contracts covering approximately 83% of our natural gas production during the first three months of 2006. Our unrealized gain (loss) on derivative contracts changed from a gain of $4.6 million during the first quarter of 2006 to a loss of $18.7 million during the first quarter of 2007, primarily as a result of a decline in the fair market value of new contracts entered into during the first quarter of 2007.

Oil Revenues. For the first three months of 2007, onshore oil revenues increased by $7.4 million, or 196%. Of the increase, $11.6 million was a result of a 206 MBbls increase in South Texas oil and natural gas liquids production, primarily from developmental drilling since the first quarter of 2006 in the Rincon and Tijerina-Canales-Blucher Fields acquired in November 2005, offset in part by a decrease of $4.2 million as a result of a decline of 27%, or $15.49 per barrel, in the average price received for onshore oil and natural gas liquids production quarter-over-quarter. This decrease in our average realized price per barrel is due in part to the decline in the market price for oil quarter-over-quarter, combined with the change in the mix of our oil and natural gas liquids production. Quarter-over-quarter, we produced more natural gas liquids which are typically sold at a lower price per barrel than oil.

Operating Expenses

	Absolute Dollars				Unit of Production - Mcfe			
	Three Months Ended March 31,				Three Months Ended March 31,			
	2007	2006	Change	%	2007	2006	Change	%

(dollars in thousands)

Lease operating expense	$ 13,174	$ 21,812	$ (8,638)	-40%	$ 0.68	$ 0.78	$ (0.10)	-13%
Severance tax	1,843	4,752	(2,909)	-61%	0.09	0.17	(0.08)	-47%
Transportation expense	2,362	2,771	(409)	-15%	0.12	0.10	0.02	20%
Asset retirement accretion expense	1,082	1,327	(245)	-18%	0.06	0.05	0.01	20%
Depreciation, depletion and amortization	57,089	83,761	(26,672)	-32%	2.93	2.98	(0.05)	-2%
General and administrative, net	10,145	8,606	1,539	18%	0.52	0.31	0.21	68%
Total operating expenses per unit of production	$ 85,695	$ 123,029	$ (37,334)	-30%	$ 4.40	$ 4.39	$ 0.01	

Total operating expenses on an absolute dollar basis decreased by 30%, from $123.0 million during the first three months of 2006 to $85.7 million during the first three months of 2007, primarily as a result of lower lease operating expense and depreciation, depletion and amortization expense following the sale of substantially all of our Gulf of Mexico assets during the first half of 2006, combined with lower severance tax expenses due to an increase in high-cost/tight-sand credits received on a portion of our South Texas production. Total per unit expenses were essentially flat at $4.40 for the first quarter of 2007 compared to $4.39 during the corresponding three months of 2006.

Lease Operating Expense. The following table summarizes our lease operating expenses on both an absolute dollar and unit of production basis for onshore and offshore properties for the three months ended March 31, 2007 and 2006:

	Absolute Dollars Three Months Ended March 31,				**Unit of Production - Mcfe Three Months Ended March 31,**			
Lease Operating Expense	**2007**	**2006**	**Change**	**%**	**2007**	**2006**	**Change**	**%**
				(dollars in thousands)				
Onshore	$ 12,791	$ 10,177	$ 2,614	26%	$ 0.66	$ 0.56	$ 0.10	18%
Offshore	383	11,635	(11,252)	-97%		1.18	(1.18)	-100%
Total lease operating expense	$ 13,174	$ 21,812	$ (8,638)	-40%	$ 0.68	$ 0.78	$ (0.10)	-13%

On an absolute dollar basis, total lease operating expense decreased by 40% during the first three months of 2007 as compared to the corresponding first three months of 2006. The quarter-over-quarter decrease reflects the disposition of substantially all of our offshore assets during the first half of 2006, offset in part by an increase of $2.6 million in lease operating expenses attributable to our onshore properties. The increase in onshore lease operating expenses quarter-over-quarter is due primarily to the continued expansion of our onshore operating base through the addition of 353 newly developed wells since the end of the first quarter of 2006 combined with higher costs to operate and maintain our existing property base, including a 30% increase in advalorem taxes quarter-over-quarter.

Severance Tax. Severance tax is a function of production volumes and revenues generated from onshore production. In addition, our severance tax expense fluctuates based on the timing of the receipt of credits and refunds from the Texas Railroad Commission on a portion of our South Texas production that qualifies as high-cost/tight-gas. On a per unit of production basis, severance tax averaged $0.09 per Mcfe during the first three months of 2007, or $0.08 per Mcfe lower than the $0.17 per Mcfe during the first three months of 2006. As onshore production increased by 7% quarter-over-quarter, the 47% decrease in per unit severance tax expense during the first three months of 2007 is primarily a result of a $2.0 million increase in high-cost/tight-gas refunds, which totaled $3.4 million during the first quarter of 2007, compared to $1.4 million received during the first quarter of 2006.

Depreciation, Depletion and Amortization. The 32% decrease in the absolute dollar amount of our depreciation, depletion and amortization expense during the first three months of 2007 compared to the corresponding first three months of 2006 was primarily a result of lower production volumes subsequent to the sale of our offshore producing assets combined with slightly lower depletion rates for the first three months of 2007. Our total depreciation, depletion and amortization rate decreased 2%, or $0.05 per Mcfe, from $2.98 per Mcfe during the first quarter of 2006 to $2.93 per Mcfe during the first quarter of 2007, primarily as a result of a $19.0 million ($12.3 million after tax) writedown in the carrying value of our natural gas and oil properties incurred during the fourth quarter of 2006.

Asset Retirement Accretion Expense. The 18% decrease in ARO accretion expense from the first quarter of 2006 to the first quarter of 2007 is primarily a result of the sale of substantially all of our Gulf of Mexico assets, offset in part by new abandonment obligations incurred as a result of our 2006 and 2007 drilling program.

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

	Absolute Dollars Three Months Ended March 31,	**Unit of Production - Mcfe Three Months Ended March 31,**

General and Administrative Expense	2007	2006	Change	%	2007	2006	Change	%
				(dollars in thousands)				
Gross general and administrative expense	$ 14,960	$ 14,398	$ 562	4%	$ 0.77	$ 0.51	$ 0.26	51%
Operating overhead reimbursements	(447)	(598)	151	-25%	(0.02)	(0.02)		
Capitalized general and administrative(1)	(4,368)	(5,194)	826	-16%	(0.22)	(0.18)	(0.04)	22%
General and administrative expense, net	$ 10,145	$ 8,606	$ 1,539	18%	$ 0.53	$ 0.31	$ 0.22	71%

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(1) Includes only those internal general and administrative costs that are directly associated with our acquisition, exploration and development activities, such as salaries, benefits and incentive compensation for geological and geophysical employees and other specifically identifiable non-payroll costs. These capitalized general and administrative costs do not include costs related to production operations, general corporate overhead or other activities that are not directly attributable to our acquisition, exploration and development efforts.

Gross general and administrative expenses during the first three months of 2007 were higher than the corresponding first three months for 2006 by $0.6 million, or 4%, and net general and administrative expenses were higher quarter-over-quarter by $1.5 million, or 18%. This increase in gross general and administrative expenses for the first three months of 2007 was due to a combination of factors, including increases in outside consulting, financial advisory, legal and accounting fees, primarily as a result of the pending merger with Forest, combined with increases in office rent and utilities, offset in part by a decrease in incentive and stock compensation expenses.

Quarter-over-quarter, capitalized general and administrative expenses were $0.8 million, or 16%, lower during the first three months of 2007 as compared to the corresponding first three months of 2006. This decrease is primarily due to a decrease in incentive and stock compensation costs related to geological and geophysical employees. In addition to the decrease in capitalized costs during the first quarter of 2007, operating overhead reimbursements also decreased quarter-over-quarter, primarily as a result of the sale of substantially all of our Gulf of Mexico assets during the first half of 2006.

On a per-unit of production basis, gross and net general and administrative expenses were higher during the first three months of 2007 and reflect the absolute dollar increase in gross general and administrative expenses resulting from higher general corporate overhead and other expenses incurred during the quarter for activities not directly associated with natural gas and oil activities, combined with the decrease in production volume quarter-over-quarter resulting primarily from the sale of our offshore assets.

Other Income and Expense, Interest and Taxes

Other Income and Expense. For the first three months of 2007, other income and expense was comprised of interest income of $0.5 million.

Interest Expense, Net of Amounts Capitalized

	Three Months Ended March 31,			
Interest and Average Borrowings	**2007**	**2006**	**Change**	%
	(in thousands, except percentages)			
Interest Expense, net:				
Gross interest [1]	$ 3,767	$ 10,376	$ (6,609)	-64%
Capitalized interest	(662)	(1,655)	993	-60%
Interest expense, net	$ 3,105	$ 8,721	$ (5,616)	-64%
Average Borrowings:				
Bank credit facility	$	$ 444,000	$ (444,000)	-100%
Senior subordinated notes	175,000	175,000		
Total borrowings	$ 175,000	$ 619,000	$ (444,000)	-72%
Average Interest Rate:				
Bank credit facility [2]	0.85%	6.26%	-5.41	-86%
Senior subordinated notes	7.00%	7.00%		

(1) Includes commitment fees, letter of credit fees, amortization of deferred financing costs and other non-loan related charges. Amortization of deferred financing costs totaled

$0.3 million and $0.4 million for the three months ended March 31, 2007 and 2006, respectively.

(2) Includes letter of credit and commitment fees.

Gross interest expense decreased by $6.6 million, or 64% during the first three months of 2007 as compared to the first three months of 2006 as a result of the repayment of all outstanding borrowings under our bank credit facility during 2006 with a portion of the proceeds received from the sale of substantially all of our Gulf of Mexico assets. Capitalized interest declined by 60% during the first three months of 2007, as compared to amounts capitalized during the first quarter of 2006. This decline corresponds directly to the $75.8 million decrease in the balance of our unevaluated

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properties related to our Gulf of Mexico assets that were sold during the first half of 2006 and lower debt levels quarter-over-quarter.

Income Tax Provision. Our provision for taxes includes both state and federal taxes. The decrease in income taxes during the first three months of 2007 corresponds to the decrease in income before taxes quarter-over-quarter, primarily as a result of the sale of our Gulf of Mexico assets during the first half of 2006.

Liquidity and Capital Resources

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

- Drilling and completing new natural gas and oil wells;
- Constructing and installing new production infrastructure;
- Acquiring additional reserves and producing properties;
- Acquiring and maintaining our lease acreage position and our seismic resources;
- Maintaining, repairing and enhancing existing natural gas and oil wells;
- Plugging and abandoning depleted or uneconomic natural gas and oil wells; and
- General and administrative costs directly associated with our acquisition, exploration and development activities, including payroll and other expenses attributable solely to our geological and geophysical employees.

To maintain the flexibility of our capital program, we typically do not enter into material long-term obligations with any of our drilling contractors or service providers with respect to our operated properties; however, we may choose to do so if we believe an opportunity is economically beneficial, as is the case with certain of our contracts for drilling rigs. See Consolidated Financial Statements, Note 3 Commitments and Contingencies *Drilling Contracts.*

Our total capital expenditure budget for 2007 has been set at an initial level of $438 million and, as of the end of the first quarter of 2007, we had spent approximately 30%, or $129.5 million. We continually evaluate our capital spending throughout the year. Actual spending levels may vary due to a variety of factors, including drilling results, natural gas prices, economic conditions, any future acquisitions, the outcome of our planned merger with Forest and the restrictions in the related merger agreement. Despite these possible variances, we believe that our operating cash flow and borrowings under our credit facility will be adequate to meet our capital and operating requirements over the next three-year period. In addition to utilizing operating cash flow and borrowings under our revolving credit facility, we believe we could finance capital expenditures with issuances of additional debt or equity securities and/or via development arrangements with industry partners. However, we are restricted by our pending merger agreement with Forest from incurring additional indebtedness outside the ordinary course of business and issuing additional equity or debt securities, among other things.

Sources of Liquidity and Capital Resources

Our primary sources of cash during the first three months of 2007 were from cash on hand and cash generated from operations. We expect to fund our future capital expenditure programs, including any future acquisitions, as well as our contractual commitments, including any required settlement of derivative contracts and our pending offer to repurchase any or all of our $175 million senior subordinated notes and related consent solicitation (see Consolidated Financial Statements, Note 5 Subsequent Events *Tender Offer and Consent Solicitation for $175 Million of 7% Senior Subordinated Notes due 2013)* with our cash flows from operations and/or borrowings under our revolving credit facility.

Available Liquidity. The following table summarizes our total available liquidity at March 31, 2007 and December 31, 2006:

	March 31, 2007	December 31, 2006
	(in thousands)	
Available Liquidity:		
Revolving credit facility borrowing base	$ 500,000	$ 500,000
Outstanding borrowings		
Letters of credit	(300)	(300)
Unused borrowing capacity	499,700	499,700
Cash and cash equivalents	29,487	53,950
Total available liquidity	$ 529,187	$ 553,650

At March 31, 2007, we had $499.7 million of available borrowing capacity under our revolving credit facility. This facility provides a lending commitment of $750 million with an additional $100 million available upon our request and with prior approval from the required lenders. Amounts available for borrowing under the credit facility are limited to a borrowing base, which was $500 million as of March 31, 2007 and, effective April 1, 2007, was reaffirmed at $500 million until the next regularly scheduled redetermination on October 1, 2007. Cash and cash equivalents totaled $29.5 million. Although we had no outstanding indebtedness under our revolving credit facility as of March 31, 2007 or as of the date of this Quarterly Report, consummation of the pending merger with Forest will require the refinancing or repayment of any outstanding indebtedness thereunder.

Cash Provided by Operating Activities. Net cash provided by operating activities decreased by 13%, or $15.5 million, from $122.1 million during the first three months of 2006 to $106.6 million during the first three months of 2007. This decrease was primarily due to production volumes, revenues and operating expenses that were all lower quarter-over-quarter, primarily as a result of the sale of substantially all of our Gulf of Mexico assets during the first half of 2006, combined with fluctuations in working capital caused by timing of cash receipts and disbursements.

At March 31, 2007, we had a working capital deficit of $33.1 million. This working capital deficit primarily is a result of a current liability of $27.7 million relating to the fair market value of our open derivative contracts payable within the next 12-month period. Our working capital balance (or deficit) fluctuates as a result of the timing and amount of cash receipts and disbursements for operating activities, including payments required under our existing derivative contracts, and borrowings or repayments under our revolving credit facility. As a result, we often have a working capital deficit or a relatively small amount of positive working capital, which we believe is typical of companies of our size in the exploration and production industry.

Uses of Liquidity and Capital Resources

During the first three months of 2007, our primary uses of cash were to fund exploration and development expenditures and payments required under derivative instruments and other contractual obligations. In addition, during the first three months of 2007, we made aggregate cash payments of $0.4 million for interest and $0.4 million for taxes. We received cash refunds of federal income taxes of $11.3 million.

Capital Expenditures. Total capital expenditures during the first three months of 2007 were $129.5 million compared to $123.1 million spent during the first three months of 2006. During the first quarter of 2007, we invested a net $129.3 million in natural gas and oil properties, and we spent $0.2 million for non-oil and gas property and equipment. Non-oil and gas property and equipment includes expenditures for information technology systems and office equipment, and compares to $0.2 million spent during the first three months of 2006. We completed the drilling of 90 gross wells (77.8 net), of which 83%, or 75 gross wells (65.0 net), were successful and 15 gross wells (12.8 net) were unsuccessful, with an additional 33 gross wells (18.9 net) in progress at March 31, 2007.

The following table summarizes our capital expenditures for natural gas and oil properties for each of the three months ended March 31, 2007 and 2006:

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	Three Months Ended March 31,	
	2007	2006
	(in thousands)	
Natural gas and oil capital expenditures		
Producing property acquisitions [1]	$ 286	$ (1,891)
Leasehold and lease acquisition costs [2]	17,746	18,879
Development	102,923	89,668
Exploration	8,377	16,277
Total natural gas and oil capital expenditures	129,332	122,933
Producing property dispositions [3]		(189,371)
Net natural gas and oil capital expenditures	$ 129,332	$ (66,438)

(1) For the three months ended March 31, 2006, includes the following: (i) deposit of $2.2 million paid for producing properties in East Texas which acquisition closed in April 2006; and (ii) a final purchase price adjustment and return of capital of $4.1 million representing a reduction to the $159.0 million purchase price paid for the South Texas properties acquired on November 30, 2005 from

Kerr-McGee Oil & Gas Onshore LP and Westport Oil and Gas Company, L.P.

(2) Leasehold costs include capitalized interest and general and administrative expenses of $5.0 million and $6.8 million, respectively, for the three-month periods ended March 31, 2007 and 2006.

(3) For the three months ended March 31, 2006, includes net proceeds from the sale of the Texas portion of our Gulf of Mexico assets of $190.8 million, net of $1.5 million in transaction fees. See Note 4 Acquisitions and Dispositions *Sale of Gulf of Mexico Assets 2006*.

Future Commitments. The following table provides estimates of the timing of future payments that we were obligated to make based on agreements in existence as of March 31, 2007. At March 31, 2007, we did not have any capital leases and did not have any borrowings outstanding under our revolving credit facility. The table includes references to our financial statements for information regarding the listed obligation.

The table below does not include any potential future commitments or contractual obligations related to our pending merger with Forest. The merger agreement contains certain termination rights for both us and Forest, including the right of either party to terminate the agreement if the merger is not consummated by September 30, 2007, and further provides that, upon termination of the merger agreement under specified circumstances, we may be required to pay to Forest a termination fee of $55 million, or Forest may be required to pay to us a termination fee of $60 million. In the event our stockholders do not adopt the merger agreement, we must pay to Forest a fee of $5 million to cover its expenses. In the event Forest s stockholders do not approve the issuance of Forest common stock in the merger, Forest must pay us a fee of $5 million to cover our expenses. In addition, upon consummation of the pending merger, we estimate that we will be obligated to pay Lehman Brothers additional financial advisory fees of approximately $7.6 million, in addition to the approximately $2.5 million already paid to Lehman Brothers in connection with this engagement as of the date of this Quarterly Report.

		Future Commitments Payments Due by Period				
	Reference	**Total**	**1 year or less**	**2 3 years**	**4 5 years**	**after 5 years**
		(in thousands)				
Contractual Obligations:						
Principal, 7% senior subordinated notes, due June 2013	Note 2	$ 175,000	$	$	$	$ 175,000
Interest, 7% senior subordinated notes, due June 2013	Note 2	79,625	12,250	24,500	24,500	18,375
Derivative instruments	Note 1	39,369	25,204	14,165		
Drilling contracts	Note 3	5,334	5,334			
Operating leases	Note 3	4,545	1,936	2,596	13	
Letters of credit	Note 3	300	300			
Unrecognized tax benefits	Note 1	1,254		1,254		
		305,427	45,024	42,515	24,513	193,375
Other Long-Term Obligations:						
Asset retirement obligations	Note 1	77,314		452	178	76,684
Supplemental Executive Retirement Plan	Note 3	3,117	100	240	322	2,455
		80,431	100	692	500	79,139
Total Contractual Obligations and Commitments:		$ 385,858	$ 45,124	$ 43,207	$ 25,013	$ 272,514

At the request of Forest, and in connection with the pending merger, we commenced a tender offer and consent solicitation to repurchase any or all of our $175 million senior subordinated notes immediately prior to the completion of the merger. The consideration to be paid by us for each $1,000 principal amount of notes tendered and accepted for payment is $1,010.00, plus accrued and unpaid interest. In addition, a consent payment in the amount of $2.50 per $1,000 principal amount of notes will be paid to those holders who consent to proposed amendments to the indenture governing the notes prior to the consent deadline. We expect to pay the total consideration of $1,012.50, plus accrued and unpaid interest, to consenting holders promptly following both the expiration time and the satisfaction or waiver of the conditions to closing of the offer. Assuming all of the holders validly tender their notes and deliver their consents, the aggregate consideration to be paid by us in connection with the tender offer and consent solicitation, including the payment of the accrued interest and all related fees and expenses, will be approximately $183.0 million. We expect to fund this payment with cash on hand and borrowings under our revolving credit facility.

In the event the merger is not consummated, Forest has agreed to reimburse us for all expenses and indemnify us against certain liabilities associated with the repurchase. Closing of the merger is not contingent on the completion of the tender offer or consent solicitation. In the event the merger is consummated but the consent solicitation is delayed, terminated or otherwise modified in a manner that does not result in the adoption of the proposed amendments, then following the closing of the pending merger and pursuant to the terms of the existing indenture, Forest will be required to offer to purchase any or all of the notes at a price equal to 101% of the aggregate principal amount, plus accrued and unpaid interest and liquidated damages, if any. See Note 5 Subsequent Events *Tender Offer and Consent Solicitation for $175 Million of 7% Senior Subordinated Notes due 2013*.

In addition, although we had no outstanding indebtedness under our bank credit facility as of March 31, 2007 or as of the date of this Quarterly Report, consummation of the pending merger will require the refinancing or repayment of any outstanding indebtedness thereunder. At March 31, 2007, our balance sheet reflects accrued interest payable on our senior subordinated notes of approximately $3.6 million.

Off-Balance Sheet Arrangements

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Market Risk

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

Interest Rate Risk

At March 31, 2007, our total debt of $175 million was comprised entirely of debt under our senior subordinated notes which bear interest at a fixed interest rate of 7% per year. Borrowings under our revolving credit facility bear interest at floating or market interest rates that are tied to the prime rate or LIBOR, at our option, and fluctuations in market interest rates will cause our annual interest costs for bank debt to fluctuate. However, at March 31, 2007, we did not have outstanding borrowings under our revolving credit facility.

Commodity Price Risk

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

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

Changes in Fair Value of Derivative Instruments

The following table summarizes the pre-tax change in the fair value of our derivative instruments for each of the three-month periods from January 1 to March 31, 2007 and 2006, and provides the fair value at the end of each period:

	Three Months Ended March 31,	
	2007	**2006**
	(in thousands)	
Change in Fair Value of Derivative Instruments:		
Fair value of contracts at January 1	$ (27,398)	$ (417,658)
Realized loss on contracts settled during period	51	46,525
(Decrease) increase in fair value of all open contracts	(12,022)	221,683
Net change during period	(11,971)	268,208
Fair value of contracts outstanding at March 31,	$ (39,369)	$ (149,450)

Derivatives in Place as of the Date of Our Report

As of the date of this Quarterly Report, the following table summarizes, on an annual basis, our natural gas hedges in place for 2007 and 2008. For the remaining nine months of 2007, we have open natural gas derivative contracts covering approximately 46% of our estimated total production volume. For 2008, we have open natural gas derivative contracts covering approximately 42% of our estimated total production volume for the months of January and February 2008, and contracts covering 8% of estimated total production for the remaining 10 months of 2008. All open derivative contracts are accounted for using mark-to-market accounting.

Year	**Period (Months)**	**Transaction Type**	**Daily Volume (MMBtu/day)**	**HSC Basis ($/MMBtu)**	**NYMEX Floor Price ($/MMBtu)**	**NYMEX Ceiling Price ($/MMBtu)**
2007	Apr Dec	Costless collar	20,000		$ 5.00	$ 6.50
2007	Apr Dec	Costless collar	10,000		5.00	6.79
2007	Apr Dec	Costless collar	20,000		7.75	9.10
2007	Apr Dec	Costless collar	10,000		7.75	9.12
2007	Apr Dec	Costless collar	10,000		7.75	9.20
2007			20,000		7.75	9.25

	Apr Dec	Costless collar				
2007	Apr Dec	Costless collar	20,000		7.75	9.30
2007	Apr Dec	Basis swap HSC	20,000	$0.2900		
2007	Apr Dec	Basis swap HSC	20,000	$0.2925		
2007	Apr Dec	Basis swap HSC	40,000	$0.3000		
2008	Jan Dec	Costless collar	20,000		$ 5.00	$ 5.72
2008	Jan Feb	Costless collar	20,000		7.75	9.10
2008	Jan Feb	Costless collar	10,000		7.75	9.12
2008	Jan Feb	Costless collar	10,000		7.75	9.20
2008	Jan Feb	Costless collar	20,000		7.75	9.25
2008	Jan Feb	Costless collar	20,000		7.75	9.30
2008	Jan Feb	Basis swap HSC	20,000	$0.2900		
2008	Jan Feb	Basis swap HSC	20,000	$0.2925		
2008	Jan Feb	Basis swap HSC	40,000	$0.3000		

For natural gas, transactions are settled based upon the NYMEX price on the final trading day of the month. With respect to the above basis swap transactions, the counterparty is required to make a payment to us if the differential between the NYMEX settlement price and the Houston Ship Channel index price for any settlement period is greater than the swap price for the transaction, and we are required to make payment to the counterparty if the differential between the NYMEX settlement price and the Houston Ship Channel index price for any settlement period is less than the swap price for the transaction. For the above costless collar transactions, the counterparty is required to make a payment to us if the NYMEX 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 NYMEX 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 NYMEX settlement price is between the floor and the ceiling prices.

Item 4. Controls and Procedures

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

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

Changes in Internal Control Over Financial Reporting

No change in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) occurred during the three months ended March 31, 2007 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

As of May 8, 2007, there have been no material changes to the risk factors previously disclosed in Item 1A. Risk Factors of our Annual Report on Form 10-K for the year ended December 31, 2006, as amended.

Item 6. Exhibits

EXHIBITS	DESCRIPTION
2.1[1]	Agreement and Plan of Merger dated as of January 7, 2007 by and among the Company, Forest Oil Corporation and MJCO Corporation (filed as exhibit 2.1 to our Current Report on Form 8-K dated January 7, 2007 (file No. 001-11899) and incorporated by reference herein).
3.1[1]	Restated Bylaws of The Houston Exploration Company, as amended April 23, 2007 (filed as Exhibit 3.1 to our Current Report on Form 8-K dated April 27, 2007 (File No. 001-11899) and incorporated by reference).
4.1[1]	Second Amendment to Rights Agreement dated as of January 7, 2007 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 January 7, 2007 (file No. 001-11899) and incorporated by reference herein).
10.1[1][2]	First Amendment to The Houston Exploration Company Supplemental Executive Retirement Plan (filed as Exhibit 10.3 to our Current Report on Form 8-K dated January 7, 2007 (File No. 001-11899) and incorporated by reference herein).
10.2[1][2]	Form of Amendment No. 2 to [Amended and Restated] Employment Agreement entered into by and between The Houston Exploration Company and each of William G. Hargett, Steven L. Mueller, James F. Westmoreland, Roger B. Rice, Joanne C. Hresko, John E. Bergeron Jr., Jeffrey B. Sherrick,

	Robert T. Ray and Carolyn M. Campbell (filed as Exhibit 10.1 to our Current Report on Form 8-K dated January 7, 2007 (file No. 001-11899) and incorporated by reference herein).
10.3(1)(2)	Second Amendment to The Houston Exploration Company Change of Control Plan (filed as exhibit 10.4 to our Current Report on Form 8-K dated January 7, 2007 (file No. 001-11899) and incorporated by reference herein).

EXHIBITS	DESCRIPTION
12.1	Computation of ratio of earnings to fixed charges.
31.1	Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Robert T. Ray, Chief Financial Officer, as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Robert T. Ray, Chief Financial Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(1) Previously filed.

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

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SIGNATURES

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

THE HOUSTON EXPLORATION COMPANY

Date: May 8, 2007	By: /s/ William G. Hargett William G. Hargett Chairman, President and Chief Executive Officer
Date: May 8, 2007	By: /s/ Robert T. Ray Robert T. Ray Senior Vice President and Chief Financial Officer
Date: May 8, 2007	By: /s/ James F. Westmoreland James F. Westmoreland Vice President and Chief Accounting Officer

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