SPINNAKER EXPLORATION CO
Form 10-Q
November 12, 2003
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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

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

For the quarterly period ended September 30, 2003.

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

For the transition period from __________ to __________ .

Commission file number 001-16009

SPINNAKER EXPLORATION COMPANY

(Exact name of registrant as specified in its charter)

Delaware **(State or other jurisdiction of** **incorporation or organization)**	**76-0560101** **(I.R.S. Employer** **Identification No.)**
1200 Smith Street, Suite 800 **Houston, Texas** **(Address of principal executive offices)**	**77002** **(Zip Code)**

(713) 759-1770

(Registrant s telephone number, including area code)

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

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

The number of shares outstanding of the registrant s common stock, par value $0.01 per share, on November 12, 2003 was 33,273,061.

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SPINNAKER EXPLORATION COMPANY

Form 10-Q

For the Three and Nine Months Ended September 30, 2003

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SPINNAKER EXPLORATION COMPANY

CONSOLIDATED BALANCE SHEETS

(In thousands, except share and per share data)

	As of September 30, 2003	As of December 31, 2002
ASSETS	**(Unaudited)**	
CURRENT ASSETS:		
Cash and cash equivalents	$ 10,645	$ 32,543
Accounts receivable, net of allowance for doubtful accounts of $3,232 at September 30, 2003 and December 31, 2002, respectively	26,700	37,572
Other	4,348	11,438
Total current assets	41,693	81,553
PROPERTY AND EQUIPMENT:		
Oil and gas, on the basis of full-cost accounting:		
Proved properties	1,104,228	879,840
Unproved properties and properties under development, not being amortized	146,492	141,326
Other	16,550	14,461
	1,267,270	1,035,627
Less Accumulated depreciation, depletion and amortization	(372,679)	(274,773)
Total property and equipment	894,591	760,854
OTHER ASSETS	83	308
Total assets	$ 936,367	$ 842,715
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 26,721	$ 29,453
Accrued liabilities and other	44,062	38,542
Hedging liabilities	5,514	19,917
Asset retirement obligations, current portion	850	
Total current liabilities	77,147	87,912
LONG-TERM DEBT	18,000	
ASSET RETIREMENT OBLIGATIONS	29,638	
DEFERRED INCOME TAXES	78,235	61,826
COMMITMENTS AND CONTINGENCIES		
EQUITY:		
Preferred stock, $0.01 par value; 10,000,000 shares authorized; no shares issued and outstanding at September 30, 2003 and December 31, 2002, respectively		
Common stock, $0.01 par value; 50,000,000 shares authorized; 33,250,276 shares issued and 33,238,752 shares outstanding at September 30, 2003 and 33,184,463 shares issued and 33,171,759 shares outstanding at December 31, 2002	333	332

Additional paid-in capital	597,087	596,087
Retained earnings	139,485	109,337
Less: Treasury stock, at cost, 11,524 shares at September 30, 2003 and 12,704 shares at December 31, 2002	(29)	(32)
Accumulated other comprehensive loss	(3,529)	(12,747)
Total equity	733,347	692,977
Total liabilities and equity	$ 936,367	$ 842,715

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

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SPINNAKER EXPLORATION COMPANY

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share data)

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
REVENUES	$ 50,138	$ 51,588	$ 177,740	$ 121,322
EXPENSES:				
Lease operating expenses	7,322	5,237	18,023	12,380
Depreciation, depletion and amortization natural gas and oil properties	30,399	31,929	94,476	70,537
Depreciation and amortization other	333	246	966	629
Accretion expense	529		1,593	
Gain on settlement of asset retirement obligations	(90)		(261)	
General and administrative	3,925	2,976	9,965	8,387
Charges related to Enron bankruptcy		128		128
Total expenses	42,418	40,516	124,762	92,061
INCOME FROM OPERATIONS	7,720	11,042	52,978	29,261
OTHER INCOME (EXPENSE):				
Interest income	49	272	176	936
Interest expense, net	(234)	(148)	(536)	(597)
Total other income (expense)	(185)	124	(360)	339
INCOME BEFORE INCOME TAXES	7,535	11,166	52,618	29,600
Income tax expense	2,713	4,020	18,943	10,656
INCOME BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	4,822	7,146	33,675	18,944
Cumulative effect of change in accounting principle (Note 3)			(3,527)	
NET INCOME	$ 4,822	$ 7,146	$ 30,148	$ 18,944
BASIC INCOME PER COMMON SHARE:				
Income before cumulative effect of change in accounting principle	$ 0.15	$ 0.22	$ 1.02	$ 0.61
Cumulative effect of change in accounting principle			(0.11)	
NET INCOME PER COMMON SHARE	$ 0.15	$ 0.22	$ 0.91	$ 0.61
DILUTED INCOME PER COMMON SHARE:				
Income before cumulative effect of change in accounting principle	$ 0.14	$ 0.21	$ 0.99	$ 0.59
Cumulative effect of change in accounting principle			(0.10)	

NET INCOME PER COMMON SHARE	$ 0.14	$ 0.21	$ 0.89	$ 0.59
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING:				
Basic	33,226	33,160	33,208	31,198
Diluted	33,865	34,038	33,806	32,118

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

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SPINNAKER EXPLORATION COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

(Unaudited)

	Nine Months Ended September 30,	
	2003	**2002**
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 30,148	$ 18,944
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	95,442	71,166
Accretion expense	1,593	
Gain on settlement of asset retirement obligations	(261)	
Deferred income tax expense	18,683	10,956
Cumulative effect of change in accounting principle	3,527	
Other	272	610
Change in operating assets and liabilities:		
Accounts receivable	10,872	(18,309)
Accounts payable and accrued liabilities	4,101	7,074
Other assets	2,130	(1,983)
Net cash provided by operating activities	166,507	88,458
CASH FLOWS FROM INVESTING ACTIVITIES:		
Oil and gas property expenditures	(205,906)	(287,998)
Proceeds from sale of natural gas and oil property and equipment	1,148	
Purchases of other property and equipment	(2,089)	(6,572)
Net cash used in investing activities	(206,847)	(294,570)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	18,000	37,000
Payments on borrowings		(37,000)
Proceeds from issuance of common stock		227,873
Common stock issuance costs		(489)
Proceeds from exercise of stock options	442	952
Net cash provided by financing activities	18,442	228,336
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(21,898)	22,224
CASH AND CASH EQUIVALENTS, beginning of year	32,543	14,061
CASH AND CASH EQUIVALENTS, end of period	$ 10,645	$ 36,285
SUPPLEMENTAL CASH FLOW DISCLOSURES:		
Cash paid for interest, net of amounts capitalized	$ 296	$ 392

Cash paid for income taxes, net	$ 260	$

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

SPINNAKER EXPLORATION COMPANY

Notes to Interim Consolidated Financial Statements (Unaudited)

September 30, 2003

1. Basis of Presentation

The accompanying unaudited consolidated financial statements of Spinnaker Exploration Company (Spinnaker or the Company) have been prepared in accordance with generally accepted accounting principles for interim financial information and the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by accounting principles generally accepted in the United States for complete financial statements. In the opinion of management, all adjustments (consisting only of normal and recurring adjustments) necessary to present a fair statement of the results for the periods included herein have been made and the disclosures contained herein are adequate to make the information presented not misleading. Interim period results are not necessarily indicative of results of operations or cash flows for a full year. These consolidated financial statements and the notes thereto should be read in conjunction with the Company s Annual Report on Form 10-K for the year ended December 31, 2002.

2. Summary of Significant Accounting Policies

Stock-Based Compensation

Statement of Financial Accounting Standards (SFAS) No. 148, Accounting for Stock-Based Compensation Transition and Disclosure, amends SFAS No. 123 to provide alternative methods of transition for an entity that voluntarily changes to the fair value based method of accounting for stock-based employee compensation and to require prominent disclosure about the effects on reported net income of an entity s accounting policy decisions with respect to stock-based employee compensation. SFAS No. 148 amends Accounting Principles Board (APB) Opinion No. 28, Interim Financial Reporting, to require disclosure about those effects in interim financial information.

SFAS No. 123, Accounting for Stock-Based Compensation, encourages, but does not require, companies to record compensation cost for stock-based employee compensation plans at fair value. The Company has chosen to account for stock-based compensation using the intrinsic value method prescribed in APB Opinion No. 25, Accounting for Stock Issued to Employees, and related interpretations. Accordingly, compensation cost for stock options is measured as the excess, if any, of the fair value of the Company s common stock, par value $0.01 per share (Common Stock), at the date of the grant over the amount an employee must pay to acquire the Common Stock. In accordance with APB Opinion No. 25, compensation cost related to stock-based compensation was $0 and less than $0.1 million in the three months ended September 30, 2003 and 2002, respectively, and $0 and $0.2 million in the nine months ended September 30, 2003 and 2002, respectively. Had compensation cost for the Company s stock option compensation plans been determined based on the fair value at the grant dates for awards under these plans consistent with the method of SFAS No. 123, the Company s pro forma net income and pro forma net income per common share would have been as follows (in thousands, except per share amounts):

	Three Months Ended September 30,	Nine Months Ended

			September 30,	
	2003	2002	2003	2002
Net income, as reported	$ 4,822	$ 7,146	$ 30,148	$ 18,944
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects		18		103
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(1,666)	(2,113)	(4,694)	(6,928)
Pro forma net income	$ 3,156	$ 5,051	$ 25,454	$ 12,119
Net income per common share:				
Basic, as reported	$ 0.15	$ 0.22	$ 0.91	$ 0.61
Basic, pro forma	$ 0.09	$ 0.15	$ 0.77	$ 0.39
Diluted, as reported	$ 0.14	$ 0.21	$ 0.89	$ 0.59
Diluted, pro forma	$ 0.09	$ 0.15	$ 0.74	$ 0.37

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Leasehold Costs

In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 141, Business Combinations, which requires the use of the purchase method of accounting for business combinations initiated after June 30, 2001 and eliminates the pooling-of-interests method. In July 2001, the FASB also issued SFAS No. 142, Goodwill and Other Intangible Assets, which discontinues the practice of amortizing goodwill and indefinite lived intangible assets and initiates an annual review of impairment. The new standard also requires that, at a minimum, all intangible assets be aggregated and presented as a separate line item in the balance sheet. The adoption of SFAS No. 141 and 142 had no impact on the Company s financial position or results of operations. A reporting issue has arisen regarding the application of certain provisions of SFAS No. 141 and 142 to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS No. 141 requires registrants to classify the costs of mineral rights associated with extracting oil and gas as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. Historically, the Company has included the costs of mineral rights associated with extracting oil and gas as a component of oil and gas properties. If it is ultimately determined that SFAS No. 141 requires oil and gas companies to classify costs of mineral rights associated with extracting oil and gas as a separate intangible assets line item on the balance sheet, the Company would be required to reclassify approximately $69.8 million and $59.0 million at September 30, 2003 and December 31, 2002, respectively, out of oil and gas properties and into a separate intangible assets line item. These costs include those to acquire contract based drilling and mineral use rights such as delay rentals, lease bonuses, commissions and brokerage fees, and other leasehold costs. The Company s cash flows and results of operations would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with full cost accounting rules, as allowed by SFAS No. 142. Further, the Company does not believe the classification of the costs of mineral rights associated with extracting oil and gas as intangible assets would have any impact on the Company s compliance with covenants under its credit facility.

Spinnaker will continue to classify its oil and gas leasehold costs as tangible oil and gas properties until further guidance is provided. The Company anticipates there will be no effect on its results of operations or cash flows.

3. Asset Retirement Obligations

Effective January 1, 2003, Spinnaker adopted SFAS No. 143, Accounting for Asset Retirement Obligations. SFAS No. 143 requires entities to record a liability for asset retirement obligations at fair value in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. As of January 1, 2003, the Company recorded asset retirement costs of $21.4 million and asset retirement obligations of $26.0 million. The cumulative effect of change in accounting principle was $3.5 million, net of taxes of $2.0 million.

The reconciliation of the beginning and ending asset retirement obligations as of September 30, 2003 is as follows (in thousands):

	Three Months Ended September 30, 2003	Nine Months Ended September 30, 2003
Asset retirement obligations, beginning of period	$ 30,117	$
Liabilities upon adoption of SFAS No. 143 on January 1, 2003		25,954
Liabilities incurred	1,210	7,055
Liabilities settled	(761)	(3,399)

Accretion expense	529	1,593
Revisions in estimated cash flows	(607)	(715)
Asset retirement obligations, as of September 30, 2003	$ 30,488	$ 30,488

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The following table summarizes the pro forma net income and earnings per share for the three and nine months ended September 30, 2002 and for the years ended December 31, 2002, 2001 and 2000 as if SFAS No. 143 had been adopted on January 1, 2000 (in thousands, except per share amounts):

	Three Months Ended September 30,	Nine Months Ended September 30,	Year Ended December 31,		
	2002	2002	2002	2001	2000
Net income:					
As reported	$ 7,146	$ 18,944	$ 31,579	$ 66,226	$ 38,566
Pro forma	6,760	17,921	30,419	65,084	37,341
Net income per share, as reported:					
Basic	$ 0.22	$ 0.61	$ 1.00	$ 2.45	$ 1.70
Diluted	0.21	0.59	0.97	2.34	1.61
Net income per share, pro forma:					
Basic	$ 0.20	$ 0.57	$ 0.96	$ 2.40	$ 1.65
Diluted	0.20	0.56	0.93	2.29	1.56

The following table summarizes pro forma asset retirement obligations as of September 30, 2002 and December 31, 2002, 2001 and 2000 as if SFAS No. 143 had been adopted on January 1, 2000 (in thousands):

	As of September 30,	As of December 31,		
	2002	2002	2001	2000
Asset retirement obligations, pro forma	$ 25,578	$ 25,949	$ 22,020	$ 15,926

4. Earnings Per Share

Basic and diluted net income per common share is computed based on the following information (in thousands, except per share amounts):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
Numerator:				
Net income	$ 4,822	$ 7,146	$ 30,148	$ 18,944

Denominator:				
Basic weighted average number of shares	33,226	33,160	33,208	31,198
Dilutive securities:				
Stock options	639	878	598	920
Diluted adjusted weighted average number of shares and assumed conversions	33,865	34,038	33,806	32,118
Basic income per common share:				
Income before cumulative effect of change in accounting principle	$ 0.15	$ 0.22	$ 1.02	$ 0.61
Cumulative effect of change in accounting principle			(0.11)	
Net income per common share	$ 0.15	$ 0.22	$ 0.91	$ 0.61
Diluted income per common share:				
Income before cumulative effect of change in accounting principle	$ 0.14	$ 0.21	$ 0.99	$ 0.59
Cumulative effect of change in accounting principle			(0.10)	
Net income per common share	$ 0.14	$ 0.21	$ 0.89	$ 0.59

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5. Credit Facility

On December 28, 2001, the Company replaced its $75.0 million credit facility with an unsecured $200.0 million credit facility (Credit Facility) with a group of seven banks. The borrowing base of the three-year Credit Facility is re-determined on a semi-annual basis each year. The banks and Spinnaker also have the option to request one additional re-determination each year. The banks determine the borrowing base in their sole discretion and in their usual and customary manner. The amount of the borrowing base is a function of the banks view of the Company s reserve profile as well as commodity prices. The current borrowing base is $100.0 million. The Company has the option to elect to use a base interest rate as described below or the LIBOR rate plus, for each such rate, a spread based on the percentage of the borrowing base used at that time. The base interest rate under the Credit Facility is a fluctuating rate of interest equal to the higher of either (i) Toronto-Dominion Bank s base rate for dollar advances made in the United States or (ii) the Federal Funds Rate plus 0.5% per annum. The commitment fee rate ranges from 0.3% to 0.5%, depending on the borrowing base usage. The Credit Facility contains various covenants and restrictive provisions. At September 30, 2003, the Company had outstanding borrowings of $18.0 million and was in compliance with the covenants and restrictive provisions under the Credit Facility. Subsequent to September 30, 2003, the Company borrowed an additional $22.0 million and expects to incur additional borrowings under the Credit Facility in the fourth quarter of 2003 and in 2004.

6. Derivatives and Hedging

The Company enters into New York Mercantile Exchange (NYMEX) related swap contracts and collar arrangements from time to time. These swap contracts and collar arrangements will settle based on the reported settlement price on the NYMEX for the last trading day of each month for natural gas.

In a swap transaction, the counterparty is required to make a payment to the Company for the difference between the fixed price and the settlement price if the settlement price is below the fixed price. The Company is required to make a payment to the counterparty for the difference between the fixed price and the settlement price if the settlement price is above the fixed price. As of September 30, 2003, Spinnaker s commodity price risk management positions in fixed price natural gas swap contracts and related fair values were as follows:

Period	Average Daily Volume (MMBtus)	Weighted Average Price (Per MMBtu)	Fair Value (in thousands)
Fourth Quarter 2003	50,000	$ 3.63	$ (5,269)

In a collar arrangement, the counterparty is required to make a payment to the Company for the difference between the fixed floor price and the settlement price if the settlement price is below the fixed floor price. The Company is required to make a payment to the counterparty for the difference between the fixed ceiling price and the settlement price if the settlement price is above the fixed ceiling price. Neither party is required to make a payment if the settlement price falls between the fixed floor price and the fixed ceiling price. As of September 30, 2003, Spinnaker s commodity price risk management positions in natural gas collar arrangements and related fair values were as follows:

Period	Average Daily Volume (MMBtus)	Weighted Average Floor Price (Per MMBtu)	Weighted Average Ceiling Price (Per MMBtu)	Fair Value (in thousands)

Fourth Quarter 2003	15,000	$	3.25	$	5.21	$	(245)

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The Company reported net liabilities of $5.5 million and $19.9 million related to its financial derivative contracts as of September 30, 2003 and December 31, 2002, respectively. Amounts related to hedging activities were as follows (in thousands):

	As of September 30, 2003	As of December 31, 2002
Current assets:		
Deferred tax asset related to hedging activities	$ 1,985	$ 7,170
Current liabilities:		
Hedging liabilities	$ 5,514	$ 19,917
Equity:		
Accumulated other comprehensive loss	$ (3,529)	$ (12,747)

The Company recognized net hedging gains (losses) and the ineffective component of the derivatives in revenues in the three and nine months ended September 30, 2003 and 2002 as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
Net hedging income (loss)	$ (6,432)	$ (1,225)	$ (33,342)	$ 7,710
Ineffective component of the derivatives loss	$ (45)	$ (28)	$	$ (69)

Based on future natural gas prices as of September 30, 2003, the Company would reclassify a net loss of $3.5 million from accumulated other comprehensive loss to earnings in the fourth quarter of 2003. The amounts ultimately reclassified into earnings will vary due to changes in the fair value of the open derivative contracts prior to settlement.

Subsequent to September 30, 2003, the fair value of Spinnaker s current commodity price risk management positions in fixed price natural gas swap contracts and natural gas collar arrangements using natural gas forward prices as of November 10, 2003, was a net liability of approximately $4.1 million, including settlements in October and November resulting in a net loss of $2.6 million.

7. Comprehensive Income

The following are components of comprehensive income (loss) (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
Net income	$ 4,822	$ 7,146	$ 30,148	$ 18,944
Other comprehensive income (loss), net of tax:				
Net change in fair value of derivative financial instruments	4,659	(7,360)	(12,121)	(3,209)
Financial derivative settlements reclassified to income	4,117	(784)	21,339	(4,935)
Comprehensive income (loss)	$ 13,598	$ (998)	$ 39,366	$ 10,800

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

Cautionary Statement About Forward-Looking Statements

Some of the information in this quarterly report on Form 10-Q contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. The forward-looking statements speak only as of the date made, and the Company undertakes no obligation to update such forward-looking statements. These forward-looking statements may be identified by the use of the words believe, expect, anticipate, will, contemplate, would and similar expressions that contemplate future events. These fu events include the following matters:

financial position;

business strategy;

budgets;

amount, nature and timing of capital expenditures, including future development costs;

drilling of wells;

natural gas and oil reserves;

timing and amount of future production of natural gas and oil;

operating costs and other expenses;

cash flow and anticipated liquidity;

prospect development and property acquisitions; and

marketing of natural gas and oil.

Numerous important factors, risks and uncertainties may affect the Company s operating results, including:

the risks associated with exploration;

delays in anticipated start-up dates;

the ability to find, acquire, market, develop and produce new properties;

natural gas and oil price volatility;

uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures;

downward revisions of proved reserves and the related negative impact on the depreciation, depletion and amortization (DD&A) rate;

production and reserves concentrated in a small number of properties;

operating hazards attendant to the natural gas and oil business;

drilling and completion risks, which costs are generally not recoverable from third parties or insurance;

potential mechanical failure or under-performance of significant wells;

impact of weather conditions on timing and costs of operations;

availability and cost of material and equipment;

actions or inactions of third-party operators of the Company s properties;

the ability to find and retain skilled personnel;

availability of capital;

the strength and financial resources of competitors;

regulatory developments;

environmental risks; and

general economic conditions.

Any of the factors listed above and other factors contained in this quarterly report could cause the Company s actual results to differ materially from the results implied by these or any other forward-looking statements made by the Company or on its behalf. The Company cannot provide assurance that future results will meet its expectations. You should pay particular attention to the risk factors and cautionary statements described in the Company s annual report on Form 10-K for the year ended December 31, 2002.

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Critical Accounting Policies

The preparation of financial statements in conformity with accounting principles generally accepted in the United States 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 date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates include DD&A of proved natural gas and oil properties. Natural gas and oil reserve estimates, which are the basis for unit-of-production DD&A and the full cost ceiling test, are inherently imprecise and are expected to change as future information becomes available. In addition, alternatives may exist among various accounting methods. In such cases, the choice of accounting method may also have a significant impact on reported amounts. The Company s critical accounting policies are as follows:

Full Cost Method of Accounting

The Company uses the full cost method of accounting for its investments in natural gas and oil properties. Under this method, all acquisition, exploration and development costs, including certain related employee costs, incurred for the purpose of exploring for and developing natural gas and oil are capitalized. Acquisition costs include costs incurred to purchase, lease or otherwise acquire property. Exploration costs include the costs of drilling exploratory wells, including those in progress, geological and geophysical service costs and depreciation of support equipment used in exploration activities. Development costs include the costs of drilling development wells and costs of completions, platforms, facilities and pipelines. Costs associated with production and general corporate activities are expensed in the period incurred. Sales of natural gas and oil properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of natural gas and oil. Application of the full cost method of accounting for oil and gas properties generally results in higher capitalized costs, no exploration costs and higher DD&A rates than the application of the successful efforts method of accounting.

DD&A

The Company computes the provision for DD&A of natural gas and oil properties using the unit-of-production method based upon production and estimates of proved reserve quantities. Unevaluated costs and related carrying costs are excluded from the amortization base until the properties associated with these costs are evaluated. In addition to costs associated with evaluated properties, the amortization base includes estimated future development costs and estimated salvage values associated with asset retirement costs.

Certain future development costs may be excluded from amortization when incurred in connection with major development projects expected to entail significant costs to ascertain the quantities of proved reserves attributable to the properties under development. The amounts that may be excluded are portions of the costs that relate to the major development project and have not previously been included in the amortization base and the estimated future expenditures associated with the development project. Such costs may be excluded from costs to be amortized until the earlier determination of whether additional reserves are proved or impairment occurs.

As of September 30, 2003, the Company excluded from the amortization base estimated future expenditures of $29.6 million associated with common development costs for its deepwater discovery on Green Canyon Blocks 338/339/382 (Front Runner). This estimate of future expenditures associated with common development costs is based on existing proved reserves to total proved reserves expected to be established upon completion of the Front Runner project.

If the $29.6 million had been included in the amortization base as of September 30, 2003, and no additional reserves were assigned to the Front Runner project, the DD&A rate as of September 30, 2003 would have been $2.72 per Mcfe, or an increase of $0.09 over the actual DD&A rate of $2.63 per Mcfe. All future development costs associated with the deepwater discovery at Front Runner are included in the determination of estimated future net cash flows from proved natural gas and oil reserves used in the full cost ceiling calculation, as discussed below.

Full Cost Ceiling

Capitalized costs of natural gas and oil properties, net of accumulated DD&A, asset retirement obligations and related deferred taxes, are limited to the estimated future net cash flows from proved natural gas and oil reserves, including the effects of hedging activities in place as of September 30, 2003, discounted at 10%, plus the lower of cost or fair value of unproved properties, as adjusted for related income tax effects (full cost ceiling). If capitalized costs of the full cost pool exceed the ceiling limitation, the excess is charged to expense.

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As of September 30, 2003, the Company s full cost ceiling, including estimated future net cash flows calculated using commodity prices of $4.97 per Mcf of natural gas and $27.90 per barrel of oil and condensate, exceeded capitalized costs of natural gas and oil properties, net of accumulated DD&A, asset retirement obligations and related deferred taxes, by approximately $99.3 million. Considering the volatility of natural gas and oil prices, it is probable that the Company s estimate of discounted future net cash flows from proved natural gas and oil reserves will change in the near term. If natural gas or oil prices decline, even if for only a short period of time, if the Company incurs significant costs associated with unsuccessful drilling operations or if the Company has downward revisions to its estimated proved reserves, it is possible that write-downs of natural gas and oil properties could occur in the future.

Capitalized Employee and Other General and Administrative Costs

Under the full cost method of accounting, certain costs are capitalized that are directly identified with acquisition, exploration and development activities. These capitalized costs include salaries, employee benefits, costs of consulting services and other related costs and do not include costs related to production, general corporate overhead or similar activities. Spinnaker capitalized employee and other general and administrative costs of $1.5 million and $1.4 million in the three months ended September 30, 2003 and 2002, respectively, and $5.0 million and $4.3 million in the nine months ended September 30, 2003 and 2002, respectively.

Unproved Properties

The costs associated with unproved properties and properties under development are not initially included in the amortization base and relate to unevaluated leasehold acreage and delay rentals, seismic data, wells in-progress and wells pending determination. Unevaluated leasehold costs and delay rentals are either transferred to the amortization base with the costs of drilling the related well or are assessed quarterly for possible impairment or reduction in value. Unevaluated leasehold costs and delay rentals are transferred to the amortization base if a reduction in value has occurred. The costs of seismic data are transferred to the amortization base using the sum-of-the-year s-digits method over a period of six years. The costs associated with wells in-progress and wells pending determination are transferred to the amortization base once a determination is made whether or not proved reserves can be assigned to the property. The costs of drilling exploratory dry holes and associated leasehold costs are included in the amortization base immediately upon determination that the well is unsuccessful.

Leasehold Costs

In June 2001, the FASB issued SFAS No. 141, Business Combinations, which requires the use of the purchase method of accounting for business combinations initiated after June 30, 2001 and eliminates the pooling-of-interests method. In July 2001, the FASB also issued SFAS No. 142, Goodwill and Other Intangible Assets, which discontinues the practice of amortizing goodwill and indefinite lived intangible assets and initiates an annual review of impairment. The new standard also requires that, at a minimum, all intangible assets be aggregated and presented as a separate line item in the balance sheet. The adoption of SFAS No. 141 and 142 had no impact on the Company s financial position or results of operations. A reporting issue has arisen regarding the application of certain provisions of SFAS No. 141 and 142 to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS No. 141 requires registrants to classify the costs of mineral rights associated with extracting oil and gas as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. Historically, the Company has included the costs of mineral rights associated with extracting oil and gas as a component of oil and gas properties. If it is ultimately determined that SFAS No. 141 requires oil and gas companies to classify costs of mineral rights associated with extracting oil and gas as a separate intangible assets line item on the balance sheet, the Company would be required to reclassify approximately $69.8 million and $59.0 million at September 30, 2003 and December 31, 2002, respectively, out of oil and gas properties and into a separate intangible assets line item. These costs include those to acquire contract based drilling and mineral use rights such as delay rentals, lease bonuses, commissions and brokerage fees, and other leasehold costs. The Company s cash flows and results of operations would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with full cost accounting rules, as allowed by SFAS No. 142. Further, the Company does not believe the classification of the costs of mineral rights associated with extracting oil and gas as intangible assets would have any impact on the Company s compliance with covenants under its credit facility.

Spinnaker will continue to classify its oil and gas leasehold costs as tangible oil and gas properties until further guidance is provided. The Company anticipates there will be no effect on its results of operations or cash flows.

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Asset Retirement Obligations

The Company recognizes the fair value of a liability for an asset retirement obligation in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying amount of the asset. The fair value of a liability for an asset retirement obligation is the amount at which that liability could be settled in a current transaction between willing parties. The Company uses the expected cash flow approach for calculating asset retirement obligations. The liability is discounted using the credit-adjusted risk-free interest rate in effect when the liability is initially recognized. The changes in the liability for an asset retirement obligation due to the passage of time are measured by applying an interest method of allocation to the amount of the liability at the beginning of the period. This amount is recognized as an increase in the carrying amount of the liability and as accretion expense classified as an operating item in the statement of operations.

Other Property and Equipment

The costs associated with seismic hardware and software are included in other property and equipment. These costs are amortized into the full cost pool using the straight-line method over three years. Amortization was $0.5 million and $0.4 million in the three months ended September 30, 2003 and 2002, respectively, and $1.5 million and $0.9 million in the nine months ended September 30, 2003 and 2002, respectively.

Stock-Based Compensation

SFAS No. 148, Accounting for Stock-Based Compensation Transition and Disclosure, amends SFAS No. 123 to provide alternative methods of transition for an entity that voluntarily changes to the fair value based method of accounting for stock-based employee compensation and to require prominent disclosure about the effects on reported net income of an entity s accounting policy decisions with respect to stock-based employee compensation. SFAS No. 148 amends APB Opinion No. 28, Interim Financial Reporting, to require disclosure about those effects in interim financial information.

SFAS No. 123, Accounting for Stock-Based Compensation, encourages, but does not require, companies to record compensation cost for stock-based employee compensation plans at fair value. The Company has chosen to account for stock-based compensation using the intrinsic value method prescribed in APB Opinion No. 25, Accounting for Stock Issued to Employees, and related interpretations. Accordingly, compensation cost for stock options is measured as the excess, if any, of the fair value of the Common Stock at the date of the grant over the amount an employee must pay to acquire the Common Stock. In accordance with APB Opinion No. 25, compensation cost related to stock-based compensation was $0 and less than $0.1 million in the three months ended September 30, 2003 and 2002, respectively, and $0 and $0.2 million in the nine months ended September 30, 2003 and 2002, respectively.

Related Parties

The Company purchases oilfield goods, equipment and services from Baker Hughes Incorporated (Baker Hughes), Cooper Cameron Corporation (Cooper Cameron) and other oilfield services companies in the ordinary course of business. The Company incurred charges of approximately $5.6 million in the first nine months of 2003 from affiliates of Baker Hughes. Mr. Michael E. Wiley, a director of Spinnaker, serves as Chairman of the Board, Chief Executive Officer and President of Baker Hughes. The Company incurred charges of less than $0.1 million in first nine months of 2003 from Cooper Cameron. Mr. Sheldon R. Erikson, a director of Spinnaker, serves as Chairman of the Board, Chief Executive Officer and President of Cooper Cameron. Spinnaker believes that these transactions are at arm s-length and the charges it pays for such goods, equipment and services are competitive with the charges and fees of other companies providing oilfield goods, equipment and services to the oil and gas exploration and production industry. Both of these companies are leaders in their respective segments of the oilfield services sector. The Company could be at a disadvantage if it were to discontinue using either company as vendors.

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Overview

Financial and operating results for the three and nine months ended September 30, 2003 compared to the same periods in 2002 included:

Three Months Ended September 30, 2003 as Compared to the Three Months Ended September 30, 2002

- Production of 11.5 billion cubic feet gas equivalent (Bcfe), down 22%.
- Revenues of $50.1 million, down 3%.
- Income from operations of $7.7 million, down 30%.
- Net income of $4.8 million, down 33%.
- Net cash provided by operating activities before changes in operating assets and liabilities of $38.8 million, down 11%.

Nine Months Ended September 30, 2003 as Compared to the Nine Months Ended September 30, 2002

- Production of 37.5 Bcfe, up 7%.
- Revenues of $177.7 million, up 47%.
- Income from operations of $53.0 million, up 81%.
- Net income of $30.1 million, up 59%.
- Net cash provided by operating activities before changes in operating assets and liabilities of $149.4 million, up 47%.

Net cash provided by operating activities before changes in operating assets and liabilities is presented because of its acceptance as an indicator of the ability of an oil and gas exploration and production company to internally fund exploration and development activities. This measure should not be considered as an alternative to net cash provided by operating activities as defined by generally accepted accounting principles. A reconciliation of net cash provided by operating activities before changes in operating assets and liabilities to net cash provided by operating activities is shown below:

	Three Months Ended September 30,	Nine Months Ended

			September 30,	
	2003	2002	2003	2002
Net cash provided by operating activities	$ 36,367	$ 46,628	$ 166,507	$ 88,458
Changes in operating assets and liabilities	2,479	(3,167)	(17,103)	13,218
Net cash provided by operating activities before changes in operating assets and liabilities	$ 38,846	$ 43,461	$ 149,404	$ 101,676

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Results of Operations

The following table sets forth certain operating information with respect to the natural gas and oil operations of the Company:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
Production:				
Natural gas (MMcf)	9,438	12,690	31,229	31,131
Oil and condensate (MBbls)	351	349	1,046	672
Total (MMcfe)	11,543	14,783	37,506	35,160
Revenues (in thousands):				
Natural gas	$ 45,967	$ 41,303	$ 178,161	$ 96,754
Oil and condensate	10,355	9,058	32,339	16,927
Net hedging income (loss)	(6,432)	1,225	(33,342)	7,710
Other	248	(28)	582	(69)
Total	$ 50,138	$ 51,558	$ 177,740	$ 121,322
Average sales price per unit:				
Natural gas revenues from production (per Mcf)	$ 4.87	$ 3.25	$ 5.71	$ 3.11
Effects of hedging activities (per Mcf)	(0.68)	0.10	(1.07)	0.25
Average price (per Mcf)	$ 4.19	$ 3.35	$ 4.64	$ 3.36
Oil and condensate revenues from production (per Bbl)	$ 29.50	$ 25.97	$ 30.91	$ 25.21
Effects of hedging activities (per Bbl)				
Average price (per Bbl)	$ 29.50	$ 25.97	$ 30.91	$ 25.21
Total revenues from production (per Mcfe)	$ 4.88	$ 3.41	$ 5.61	$ 3.23
Effects of hedging activities (per Mcfe)	(0.56)	0.08	(0.89)	0.22
Total average price (per Mcfe)	$ 4.32	$ 3.49	$ 4.72	$ 3.45
Expenses (per Mcfe):				
Lease operating expenses	$ 0.63	$ 0.35	$ 0.48	$ 0.35
Depreciation, depletion and amortization natural gas and oil properties	$ 2.63	$ 2.16	$ 2.52	$ 2.01
Income from operations (in thousands)	$ 7,720	$ 11,042	$ 52,978	$ 29,261

Three Months Ended September 30, 2003 as Compared to the Three Months Ended September 30, 2002

Revenues, including the effects of hedging activities, decreased $1.4 million in the third quarter of 2003 compared to the third quarter of 2002. The decrease in revenues was primarily due to a decrease in net hedging income and a decrease in natural gas production, partially offset by higher natural gas and oil revenues resulting from higher average commodity prices in the third quarter of 2003 compared to the same period in 2002. Excluding the effects of hedging activities, natural gas revenues increased $4.7 million and oil and condensate revenues increased $1.3

million. Revenues from natural gas hedging activities and other were negatively impacted by $7.4 million in the third quarter of 2003 compared to the same period of 2002.

Production decreased approximately 3.2 Bcfe in the third quarter of 2003 compared to the third quarter of 2002. Average daily production in the third quarter of 2003 was 125 million cubic feet gas equivalent (MMcfe) compared to 161 MMcfe in the same period of 2002. Natural gas revenues increased $4.7 million due to higher prices in the third quarter of 2003, although production decreased approximately 3.3 Bcf. Excluding the effects of hedging activities, the third quarter 2003 average natural gas price was $4.87 per Mcf compared to $3.25 per Mcf in the third quarter of 2002. Oil and condensate revenues increased $1.3 million due to higher prices and increased production of two thousand barrels (MBbls) in the third quarter of 2003. The third quarter 2003 average oil and condensate price was $29.50 per barrel compared to $25.97 per barrel in the same period of 2002.

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Lease operating expenses increased $2.1 million in the third quarter of 2003 compared to the third quarter of 2002. Of the total increase in lease operating expenses, approximately $2.6 million related to increased workover activities and $0.6 million was related to activity on blocks that commenced production subsequent to September 30, 2002, offset in part by approximately $1.1 million related to decreased expenses on existing properties. The overall increase in the lease operating expense rate per Mcfe in the third quarter of 2003 compared to the same period of 2002 was primarily due to a planned pipeline workover on Green Canyon 177 (Sangria) of $2.7 million, or $0.23 per Mcfe.

DD&A decreased $1.5 million in the third quarter of 2003 compared to the third quarter of 2002. Of the total decrease in DD&A, $8.5 million related to lower production volumes of 3.2 Bcfe, offset in part by $7.0 million related to an increase in the DD&A rate per Mcfe in the third quarter of 2003 compared to the same period of 2002. The increase in the DD&A rate was primarily due to costs associated with unsuccessful wells in the third quarter of 2003. Other depreciation and amortization increased $0.1 million as a result of additions to other property and equipment.

General and administrative expenses increased $0.9 million in the third quarter of 2003 compared to the third quarter of 2002. Of the total increase in general and administrative expenses, approximately $0.6 million was primarily due to higher employment-related costs associated with an increase in the number of employees subsequent to September 30, 2002 and approximately $0.3 million related to an increase in legal and accounting fees.

Interest income decreased $0.2 million in the third quarter of 2003 compared to the third quarter of 2002 primarily due to lower average cash investment balances and lower interest rates in the third quarter of 2003. Interest expense increased $0.1 million in the third quarter of 2003 compared to the third quarter of 2002 primarily due to interest associated with borrowings of $18.0 million in the third quarter of 2003.

Income tax expense decreased $1.3 million due to lower earnings in the third quarter of 2003 compared to the third quarter of 2002. Income taxes were accrued at a 36% effective tax rate in the third quarter of 2003 and 2002.

The Company recognized net income of $4.8 million, or $0.15 per basic and $0.14 per diluted share, in the third quarter of 2003 compared to net income of $7.1 million, or $0.22 per basic share and $0.21 per diluted share, in the third quarter of 2002.

Nine Months Ended September 30, 2003 as Compared to the Nine Months Ended September 30, 2002

Revenues, including the effects of hedging activities, increased $56.4 million in the first nine months of 2003 compared to the first nine months of 2002. The increase in revenues was primarily due to increased production and higher natural gas and oil prices in the first nine months of 2003. Excluding the effects of hedging activities, natural gas revenues increased $81.4 million and oil and condensate revenues increased $15.4 million. Revenues from natural gas hedging activities and other were negatively impacted by $40.4 million in the first nine months of 2003 compared to the same period of 2002.

Production increased approximately 2.3 Bcfe in the first nine months of 2003 compared to the first nine months of 2002. Average daily production in the first nine months of 2003 was 137 MMcfe compared to 129 MMcfe in the same period of 2002. Natural gas revenues increased $81.4 million primarily due to higher prices in the first nine months of 2003. Excluding the effects of hedging activities, the average natural gas price was $5.71 per Mcf in the first nine months of 2003 compared to $3.11 per Mcf in the same period of 2002. Oil and condensate revenues increased $15.4 million due to increased production of 374 MBbls and higher prices in the first nine months of 2003. The average oil and condensate price was $30.91 per barrel in the first nine months of 2003 compared to $25.21 per barrel in the same period of 2002.

Lease operating expenses increased $5.6 million in the first nine months of 2003 compared to the first nine months of 2002. Of the total increase in lease operating expenses, approximately $2.6 million was primarily attributable to higher operating expenses on existing producing properties, $2.0 million related to increased workover activities and $1.0 million was related to activity on blocks that commenced production subsequent to September 30, 2002. The overall increase in the lease operating expense rate per Mcfe in the first nine months of 2003 compared to the same period of 2002 was primarily due to a planned pipeline workover on Green Canyon 177 (Sangria) of $2.7 million, or $0.07 per Mcfe.

DD&A increased $23.9 million in the first nine months of 2003 compared to the first nine months of 2002. Of the total increase in DD&A, $18.0 million related to an increase in the DD&A rate per Mcfe and $5.9 million related to higher production volumes of 2.3 Bcfe in the first nine months of 2003 compared to the same period in 2002. The increase in the DD&A rate was primarily due to unsuccessful wells and higher finding costs associated with discoveries since September 30, 2002. Other depreciation and amortization increased $0.3 million as a result of additions to other property and equipment.

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General and administrative expenses increased $1.6 million in the first nine months of 2003 compared to the first nine months of 2002. The increase in general and administrative expenses was primarily due to higher employment-related costs associated with an increase in the number of employees subsequent to September 30, 2002.

Interest income decreased $0.8 million in the first nine months of 2003 compared to the first nine months of 2002 primarily due to lower average cash investment balances and lower interest rates in the first nine months of 2003. Interest expense decreased $0.1 million in the first nine months of 2003 compared to the same period of 2002 due to lower borrowings in the first nine months of 2003.

Income tax expense increased $8.3 million due to higher earnings in the first nine months of 2003 compared to the first nine months of 2002. Income taxes were accrued at a 36% effective tax rate in the first nine months of 2003 and 2002.

The Company recognized net income of $30.1 million, or $0.91 per basic share and $0.89 per diluted share, in the first nine months of 2003 compared to net income of $18.9 million, or $0.61 per basic share and $0.59 per diluted share, in the first nine months of 2002.

Liquidity and Capital Resources

The Company has experienced and expects to continue to experience substantial capital requirements, primarily due to its active exploration and development programs in the Gulf of Mexico. Spinnaker has capital expenditure plans for 2003 totaling approximately $275 million. Additions to property and equipment of $231.6 million in the first nine months of 2003 included asset retirement costs of $27.7 million. Spinnaker has participated in a significant deepwater oil discovery, Front Runner, with a 25% non-operator working interest. Spinnaker has incurred inception-to-date capital expenditures associated with Front Runner of $124.8 million. As of September 30, 2003, the Company expects to incur approximately $60.9 million in future development costs related to Front Runner, including approximately $6.6 million in the remainder of 2003, $22.0 million in 2004 and $32.3 million thereafter.

Natural gas and oil prices have a significant impact on the Company s cash flows available for capital expenditures and its ability to borrow and raise additional capital. The amount the Company can borrow under its Credit Facility is subject to periodic re-determination based in part on changing expectations of future prices. Lower prices may also reduce the amount of natural gas and oil that the Company can economically produce. Lower prices and/or lower production may decrease revenues, cash flows and the borrowing base under the Credit Facility, thus reducing the amount of financial resources available to meet the Company s capital requirements. The Company believes that working capital, cash flows from operations, proceeds from available borrowings under its Credit Facility and Front Runner spar production facility financing opportunities will be sufficient to meet its capital requirements in the next twelve months. However, additional debt or equity financing may be required in the future to fund growth and exploration and development programs. In the event additional capital resources are unavailable, the Company may curtail its drilling, development and other activities or be forced to sell some of its assets on an untimely or unfavorable basis. At September 30, 2003, the Company had borrowings of $18.0 million and was in compliance with the covenants and restrictive provisions under the Credit Facility. Subsequent to September 30, 2003, the Company borrowed an additional $22.0 million and expects to incur additional borrowings under the Credit Facility in the fourth quarter of 2003 and in 2004.

Spinnaker has an effective shelf registration statement relating to the potential public offer and sale by the Company or certain of its affiliates of up to $500.0 million of any combination of debt securities, preferred stock, common stock, warrants, stock purchase contracts and trust preferred securities from time to time or when financing needs arise. The registration statement does not provide assurance that the Company will or could sell any such securities.

Cash and cash equivalents decreased $21.9 million to $10.6 million as of September 30, 2003. The components of the decrease in cash and cash equivalents included $166.5 million provided by operating activities, $206.8 million used in investing activities and $18.4 million provided by financing activities.

Operating Activities

Net cash provided by operating activities in the first nine months of 2003 increased 88% to $166.5 million primarily due to higher commodity prices and increased production. Cash flow from operations is dependent upon the Company s ability to increase production through its exploration and development programs and the prices of natural gas and oil. The Company has made significant investments to expand its operations in the Gulf of Mexico.

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The Company sells its natural gas and oil production under fixed or floating market price contracts. Spinnaker enters into hedging arrangements from time to time to reduce its exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. However, these contracts also limit the benefits the Company would realize if prices increase. See Item 3. Quantitative and Qualitative Disclosures About Market Risk.

The Company s cash flow from operations also depends on its ability to manage working capital, including accounts receivable, accounts payable and accrued liabilities. The net decrease of $10.9 million in accounts receivable was primarily related to a decrease of $5.9 million in joint interest billings and other as a result of Spinnaker s higher working interests in projects in the third quarter of 2003 compared to the end of 2002 and a decrease of $5.0 million in oil and gas revenue receivable due to decreased production and lower oil prices in September 2003 compared to December 2002.

Investing Activities

Net cash used in investing activities was $206.8 million in the first nine months of 2003 and included oil and gas property capital expenditures of $205.9 million and purchases of other property and equipment of $2.0 million. The Company received proceeds of $1.1 million from the sale of natural gas and oil property and equipment in the first quarter of 2003.

As part of its strategy, the Company explores for natural gas and oil at deeper drilling depths and in the deep waters of the Gulf of Mexico, where operations are more difficult and costly than at shallower drilling depths and in shallower waters. Along with higher risks and costs associated with these areas, greater opportunity exists for reserve additions. The Company has experienced and will continue to experience significantly higher drilling costs for its deep shelf and deepwater projects relative to the drilling costs on shallower depth shelf projects in the Gulf of Mexico. The Company drilled 24 wells in the first nine months of 2003, 17 of which were successful. The Company drilled 26 wells in 2002, 14 of which were successful. Since inception and through September 30, 2003, the Company drilled 144 wells, 87 of which were successful, representing a success rate of 60%. Dry hole costs, including associated leasehold costs, were $28.4 million in the first nine months of 2003.

The Company has capital expenditure plans for 2003 totaling approximately $275 million, primarily for costs related to exploration and development programs. The Company settled asset retirement obligations of $3.4 million in the first nine months of 2003 and does not anticipate any other significant abandonment or dismantlement expenditures in the remainder of 2003. Actual levels of capital expenditures may vary due to many factors, including drilling results, natural gas and oil prices, the availability of capital, industry conditions, acquisitions, decisions of operators and other prospect owners and the prices of drilling rig dayrates and other oilfield goods and services. The costs associated with unproved properties and properties under development not included in the amortization base were as follows (in thousands):

	As of September 30, 2003	As of December 31, 2002
Leasehold, delay rentals and seismic data	$ 116,309	$ 122,409
Wells in-progress	7,312	17,639
Wells pending determination	21,177	
Other	1,694	1,278
Total	$ 146,492	$ 141,326

Financing Activities

Net cash provided by financing activities of $18.4 million in the first nine months of 2003 related to proceeds of $18.0 million from borrowings and $0.4 million from stock option exercises.

On December 28, 2001, the Company replaced its $75.0 million credit facility with an unsecured $200.0 million Credit Facility with a group of seven banks. The borrowing base of the three-year Credit Facility is re-determined on a semi-annual basis each year. The banks and Spinnaker also have the option to request one additional re-determination each year. The banks determine the borrowing base in their sole discretion and in their usual and customary manner. The amount of the borrowing base is a function of the banks view of the Company s reserve profile as well as commodity prices. The current borrowing base is $100.0 million. The Company has the option to elect to use a base interest rate as described below or the LIBOR rate plus, for each such rate, a spread based on the percentage of the borrowing base used at that time. The base interest rate under the Credit Facility is a fluctuating rate of interest equal to the higher of either (i) Toronto-Dominion Bank s base rate for dollar advances made in the United States or (ii) the Federal Funds Rate plus 0.5% per annum. The commitment fee rate ranges from 0.3% to 0.5%, depending on the borrowing base usage. The Credit Facility contains various covenants and restrictive provisions that are disclosed in the Company s annual report on Form 10-K for the year ended December 31, 2002.

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At September 30, 2003, the Company had borrowings of $18.0 million and was in compliance with the covenants and restrictive provisions under the Credit Facility. Subsequent to September 30, 2003, the Company borrowed an additional $22.0 million and expects to incur additional borrowings under the Credit Facility in the fourth quarter of 2003 and in 2004.

Contractual Obligations

The Company leases administrative offices, office equipment and oil and gas equipment under non-cancelable operating leases. As of September 30, 2003, the Company had $18.0 million outstanding in borrowings under the Credit Facility, which is due on December 28, 2004. The Company had no capital lease or purchase obligations or other contractual long-term liabilities as of September 30, 2003, except for obligations incurred in the ordinary course of business.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

The Company is exposed to changes in interest rates. Changes in interest rates affect the interest earned on cash and cash equivalents and the interest rate paid on borrowings under the Credit Facility. The Company does not currently use interest rate derivative financial instruments to manage exposure to interest rate changes, but may do so in the future.

Commodity Price Risk

The Company s revenues, profitability and future growth depend substantially on prevailing prices for natural gas and oil. Prices also affect the amount of cash flow available for capital expenditures and the Company s ability to borrow and raise additional capital. Lower prices may also reduce the amount of natural gas and oil that the Company can economically produce. The Company sells its natural gas and oil production under fixed or floating market price contracts. Spinnaker enters into hedging arrangements from time to time to reduce its exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. Spinnaker does not enter into such hedging arrangements for trading purposes. However, these contracts also limit the benefits the Company would realize if prices increase. The Company s current financial derivative contracts include fixed price swap contracts and cashless collar arrangements that have been placed with major trading counterparties the Company believes represent minimum credit risks. Spinnaker cannot provide assurance that these trading counterparties will not become credit risks in the future. Under its current hedging practice, the Company generally does not hedge more than 66 $^{2}/3$% of its estimated twelve-month production quantities without the prior approval of the risk management committee of the board of directors.

The Company enters into NYMEX related swap contracts and collar arrangements from time to time. These swap contracts and collar arrangements will settle based on the reported settlement price on the NYMEX for the last trading day of each month for natural gas.

In a swap transaction, the counterparty is required to make a payment to the Company for the difference between the fixed price and the settlement price if the settlement price is below the fixed price. The Company is required to make a payment to the counterparty for the difference between the fixed price and the settlement price if the settlement price is above the fixed price. As of September 30, 2003, Spinnaker s commodity price risk management positions in fixed price natural gas swap contracts and related fair values were as follows:

Period	Average Daily Volume (MMBtus)	Weighted Average Price (Per MMBtu)	Fair Value (in thousands)
Fourth Quarter 2003	50,000	$ 3.63	$ (5,269)

In a collar arrangement, the counterparty is required to make a payment to the Company for the difference between the fixed floor price and the settlement price if the settlement price is below the fixed floor price. The Company is required to

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make a payment to the counterparty for the difference between the fixed ceiling price and the settlement price if the settlement price is above the fixed ceiling price. Neither party is required to make a payment if the settlement price falls between the fixed floor price and the fixed ceiling price. As of September 30, 2003, Spinnaker s commodity price risk management positions in natural gas collar arrangements and related fair values were as follows:

Period	Average Daily Volume (MMBtus)	Weighted Average Floor Price (Per MMBtu)	Weighted Average Ceiling Price (Per MMBtu)	Fair Value (in thousands)
Fourth Quarter 2003	15,000	$ 3.25	$ 5.21	$ (245)

The Company reported net liabilities of $5.5 million and $19.9 million related to its financial derivative contracts as of September 30, 2003 and December 31, 2002, respectively. Amounts related to hedging activities were as follows (in thousands):

	As of September 30, 2003	As of December 31, 2002
Current assets:		
Deferred tax asset related to hedging activities	$ 1,985	$ 7,170
Current liabilities:		
Hedging liabilities	$ 5,514	$ 19,917
Equity:		
Accumulated other comprehensive loss	$ (3,529)	$ (12,747)

The Company recognized net hedging gains (losses) and the ineffective component of the derivatives in revenues in the three and nine months ended September 30, 2003 and 2002 as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
Net hedging income (loss)	$ (6,432)	$ (1,225)	$ (33,342)	$ 7,710

Ineffective component of the derivatives loss	$ (45)	$ (28)	$	$ (69)

Based on future natural gas prices as of September 30, 2003, the Company would reclassify a net loss of $3.5 million from accumulated other comprehensive loss to earnings in the fourth quarter of 2003. The amounts ultimately reclassified into earnings will vary due to changes in the fair value of the open derivative contracts prior to settlement.

To calculate the potential effect of the derivative contracts on future revenues, the Company applied NYMEX natural gas forward prices as of September 30, 2003 to the quantity of the Company s natural gas production covered by those derivative contracts as of that date. The following table shows the estimated potential effects of the derivative financial instruments on future revenues (in thousands):

Derivative Instrument	**Estimated Decrease in Revenues at Current Prices**	**Estimated Decrease in Revenues with 10% Decrease in Prices**	**Estimated Decrease in Revenues with 10% Increase in Prices**
Fixed price swap transactions	$ (5,269)	$ (3,763)	$ (6,788)
Collar arrangements	$ (245)	$ (126)	$ (298)

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Subsequent to September 30, 2003, the fair value of Spinnaker s current commodity price risk management positions in fixed price natural gas swap contracts and natural gas collar arrangements using natural gas forward prices as of November 10, 2003, was a net liability of approximately $4.1 million, including settlements in October and November resulting in a net loss of $2.6 million.

Item 4. Controls and Procedures

Our Chief Executive Officer and Chief Financial Officer performed an evaluation of our disclosure controls and procedures, which have been designed to permit us to effectively identify and timely disclose important information. They concluded that the controls and procedures were effective as of September 30, 2003. During the three months ended September 30, 2003, we made no change in our internal controls over financial reporting that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

PART II - OTHER INFORMATION

Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits

See Exhibit Index.

(b) Reports on Form 8-K

A Current Report on Form 8-K dated July 31, 2003 and furnished on August 1, 2003 provided second quarter 2003 earnings and operations information through July 31, 2003 pursuant to Item 12, Results of Operations and Financial Condition.

A Current Report on Form 8-K dated August 5, 2003 and furnished on August 6, 2003 announced the appointment of William N. Young, III as Vice President Marketing pursuant to Item 9, Regulation FD Disclosure.

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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.

SPINNAKER EXPLORATION COMPANY

Date:	November 12, 2003	By:	/s/ ROBERT M. SNELL
			Robert M. Snell Vice President, Chief Financial Officer and Secretary
Date:	November 12, 2003	By:	/s/ JEFFREY C. ZARUBA
			Jeffrey C. Zaruba Vice President, Treasurer and Assistant Secretary

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EXHIBIT INDEX

Exhibit Number	Description
12.1	Calculation of Ratios of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Dividends
31.1	Certification of Principal Executive Officer of Spinnaker Exploration Company Pursuant to Section 302 of the Sarbanes-Oxley Act
31.2	Certification of Principal Financial Officer of Spinnaker Exploration Company Pursuant to Section 302 of the Sarbanes-Oxley Act
32.1	Certification of Chief Executive Officer of Spinnaker Exploration Company Pursuant to 18 U.S.C. § 1350
32.2	Certification of Chief Financial Officer of Spinnaker Exploration Company Pursuant to 18 U.S.C. § 1350