SPINNAKER EXPLORATION CO
Form 10-Q
November 13, 2002

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, 2002.

(_) Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.

Commission file number 001-16009

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

Delaware	76-0560101
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification N

1200 Smith Street, Suite 800 Houston, Texas	77002
(Address of principal executive offices)	(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 ____

The number of shares outstanding of the registrant's common stock, par value $0.01 per share, on November 12, 2002 was 33,170,740.

SPINNAKER EXPLORATION COMPANY
Form 10-Q
For the Three and Nine Months Ended September 30, 2002

SPINNAKER EXPLORATION COMPANY
CONSOLIDATED BALANCE SHEETS
(In thousands, except share and per share data)

	Sept
ASSETS	(Una
CURRENT ASSETS:	
Cash and cash equivalents	$ 3
Accounts receivable, net of allowance for doubtful accounts of $3,187 at September 30, 2002 and $3,059 at December 31, 2001, respectively	4
Hedging assets	
Other	
Total current assets	8
PROPERTY AND EQUIPMENT:	
Oil and gas, on the basis of full-cost accounting:	
Proved properties	81
Unproved properties and properties under development, not being amortized	14

Other	1
	97
Less - Accumulated depreciation, depletion and amortization	(23
Total property and equipment	73
OTHER ASSETS	
Total assets	$ 82

LIABILITIES AND EQUITY

CURRENT LIABILITIES:	
Accounts payable	$ 2
Accrued liabilities and other	4
Hedging liabilities	1
Total current liabilities	8
OTHER LIABILITIES	
DEFERRED INCOME TAXES	5
COMMITMENTS AND CONTINGENCIES	
EQUITY:	
Preferred stock, $0.01 par value; 10,000,000 shares authorized; no shares issued and outstanding at September 30, 2002 and December 31, 2001, respectively	
Common stock, $0.01 par value; 50,000,000 shares authorized; 33,181,065 shares issued and 33,167,561 shares outstanding at September 30, 2002 and 27,308,912 shares issued and 27,293,264 shares outstanding at December 31, 2001	
Additional paid-in capital	59
Retained earnings	9
Less: Treasury stock, at cost, 13,504 and 15,648 shares at September 30, 2002 and December 31, 2001, respectively	
Accumulated other comprehensive income (loss)	(
Total equity	68
Total liabilities and equity	$ 82

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

SPINNAKER EXPLORATION COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share data)
(Unaudited)

	For the Three Months Ended September 30,		Fo En
	2002	2001	200

REVENUES	$ 51,558	$ 44,818	$ 121
EXPENSES:			
Lease operating expenses	5,237	3,309	12
Depreciation, depletion and amortization - natural gas and oil properties	31,929	23,009	70
Depreciation and amortization - other	246	131	
General and administrative	2,976	2,219	8
Charges related to Enron bankruptcy	128	-	
Total expenses	40,516	28,668	92
INCOME FROM OPERATIONS	11,042	16,150	29
OTHER INCOME (EXPENSE):			
Interest income	272	777	
Interest expense	(148)	(48)	
Total other income (expense)	124	729	
INCOME BEFORE INCOME TAXES	11,166	16,879	29
Income tax provision	4,020	6,076	10
NET INCOME	$ 7,146	$ 10,803	$ 18
NET INCOME PER COMMON SHARE:			
Basic	$ 0.22	$ 0.40	$
Diluted	$ 0.21	$ 0.38	$
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING:			
Basic	33,160	27,172	31
Diluted	34,038	28,335	32

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)

CASH FLOWS FROM OPERATING ACTIVITIES:	
Net income	$

Adjustments to reconcile net income to net cash provided by (used in) operating activities:	
Depreciation, depletion and amortization	
Deferred income tax expense	
Other	
Change in components of working capital:	
Accounts receivable	
Accounts payable and accrued liabilities	
Other current assets and other	
Net cash provided by operating activities	
CASH FLOWS FROM INVESTING ACTIVITIES:	
Additions to oil and gas properties	(
Purchases of other property and equipment	
Purchases of short-term investments	
Sales of short-term investments	
Net cash used in investing activities	(
CASH FLOWS FROM FINANCING ACTIVITIES:	
Proceeds from borrowings	
Payments on borrowings	
Proceeds from issuance of common stock	
Common stock issuance costs	
Proceeds from exercise of stock options	
Net cash provided by financing activities	
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	
CASH AND CASH EQUIVALENTS, beginning of year	
CASH AND CASH EQUIVALENTS, end of period	$
SUPPLEMENTAL CASH FLOW DISCLOSURES:	
Cash paid for interest, net of amounts capitalized	$
Cash paid for income taxes	$

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

SPINNAKER EXPLORATION COMPANY
Notes to Interim Consolidated Financial Statements (Unaudited)
September 30, 2002

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, 2001.

2. Earnings Per Share

The basic and diluted net income per common share calculations are based on the following information (in thousands, except per share amounts):

	Three Months Ended September 30,	
	2002	2001
Numerator:		
Net income	$ 7,146	$ 10,803
Denominator:		
Basic weighted average number of shares	33,160	27,172
Dilutive securities:		
Stock options	878	1,163
Diluted adjusted weighted average number of shares and assumed conversions	34,038	28,335
Net income per common share:		
Basic	$ 0.22	$ 0.40
Diluted	$ 0.21	$ 0.38

3. 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 or about April 30 and September 30 each year. The banks and Spinnaker also have the option to request one additional re-determination each year. The borrowing base is determined by the banks, in their usual and customary manner, and at their sole discretion. 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 percent 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 Toronto-Dominion Bank's base rate for dollar advances made in the United States or the Federal Funds Rate plus 0.5 percent per annum. The commitment fee rate ranges from 0.3 percent to 0.5 percent, depending on the borrowing base usage. The Credit Facility contains various covenants and restrictive provisions. At September 30, 2002, the Company was in compliance with the covenants and restrictive provisions and expects to remain in compliance through December 31, 2002. As of November 12, 2002, the Company had no outstanding borrowings under the Credit Facility.

4. Equity Offering

On April 3, 2002, the Company completed a public offering of 5,750,000 shares of common stock, par value $0.01 per share ("Common Stock"), at $41.50 per share, including the over-allotment option consisting of 750,000 shares. After payment of underwriting discounts and commissions, the Company received net proceeds of $227.9 million. On April 3, 2002, the Company used a portion of the proceeds from the offering to repay outstanding borrowings of $37.0 million. The remaining net proceeds were invested in short-term high quality investments and are being used to fund a portion of the costs to develop the Company's deep water oil discovery at Green Canyon Blocks 338/339 ("Front Runner"), to fund a portion of exploration and other development activities and for general corporate purposes, including possible acquisitions of properties or seismic data.

5. Derivatives and Hedging

On January 1, 2001, the Company adopted Statement of Financial Accounting Standards ("SFAS") No. 133, as amended, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 established accounting and reporting standards requiring that all derivative instruments be recorded in the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in a derivative's fair value be realized currently in earnings unless specific hedge accounting criteria are met. Accounting for qualifying hedges allows derivative gains and losses to offset related results on the hedged items in the statement of operations and requires a company to formally document, designate and assess the effectiveness of transactions that qualify for hedge accounting.

The Company enters into New York Mercantile Exchange ("NYMEX") related swap contracts and collar arrangements from time to time. The Company's 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, 2002, Spinnaker's commodity price risk management positions in fixed price natural gas swap contracts and related fair value were as follows:

Period	Average Daily Volume (MMBtus)	Weighted Average Price (Per MMBtu)	Fair Value (in thousands)
Fourth Quarter 2002	106,685	$ 3.68	$ (3,510)
First Quarter 2003	60,000	3.71	(2,558)
Second Quarter 2003	53,297	3.55	(1,978)
Third Quarter 2003	50,000	3.55	(2,001)
Fourth Quarter 2003	50,000	3.63	(2,223)

Total	$ (12,270)

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, 2002, Spinnaker's commodity price risk management positions in natural gas collar arrangements and related fair value were as follows:

Period	Average Daily Volume (MMBtu)	Weighted Average Floor Price (Per MMBtu)	Weighte Average Ceiling Pr (Per MMBt
First Quarter 2003	15,000	$ 3.25	$ 5.21
Second Quarter 2003	15,000	3.25	5.21
Third Quarter 2003	15,000	3.25	5.21
Fourth Quarter 2003	15,000	3.25	5.21
Total			

The Company reported a net liability of $12.6 million related to its derivative contracts at September 30, 2002. The components of the net liability were as follows (in thousands):

	As of September 30, 2002	As of December 31, 2001
Current:		
Hedging asset	$ 23	$ 20,593
Hedging liability	10,202	-
Non-current:		
Hedging asset	$ -	$ 1,726
Hedging liability	2,455	-

The Company also reported a loss in accumulated other comprehensive income of $8.1 million, net of income taxes of $4.4 million. The ineffective component of the derivatives recognized in earnings was a loss less than $0.1 million in the first nine months of 2002.

In connection with monthly settlements, the Company recognized net hedging gains of $1.2 million and $7.7 million in revenues in the third quarter and first nine months of 2002, respectively. Based on future natural gas prices as of September 30, 2002, the Company would reclassify a net loss of $10.2 million from accumulated other comprehensive income (loss) to earnings within the next twelve months. 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, 2002, Spinnaker entered into additional swap contracts for the fourth quarter of 2002. Spinnaker's current commodity price risk management positions in fixed price natural gas swap contracts and the related fair values, using natural gas forward prices as of November 11, 2002 and including October and November 2002 settlements paid to counterparties of $2.0 million were as follows:

Period	Average Daily Volume (MMBtu)	Weighted Average Price (Per MMBtu)	Fair Value (in thousands)
Fourth Quarter 2002	113,315	$ 3.71	$ (1,592)
First Quarter 2003	60,000	3.71	(843)
Second Quarter 2003	53,297	3.55	(857)
Third Quarter 2003	50,000	3.55	(1,013)
Fourth Quarter 2003	50,000	3.63	(1,474)
Total			$ (5,779)

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Spinnaker's current commodity price risk management positions in natural gas collar arrangements as of November 11, 2002 were as follows:

Period	Average Daily Volume (MMBtu)	Weighted Average Floor Price (Per MMBtu)	Weighted Average Ceiling Price (Per MMBtu)
First Quarter 2003	15,000	$ 3.25	$ 5.21
Second Quarter 2003	15,000	3.25	5.21
Third Quarter 2003	15,000	3.25	5.21
Fourth Quarter 2003	15,000	3.25	5.21

6. Comprehensive Income

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

	Three Months Ended September 30,		Nine Se
	2002	2001	2002

Net income	$ 7,146	$ 10,803	$ 18,9
Other comprehensive income (loss), net of tax:			
Cumulative effect of accounting change for derivative financial instruments	-	-	
Net change in fair value of derivative financial instruments	(7,360)	17,128	(3,2
Financial derivative settlements taken to income, net of tax	(784)	(1,640)	(4,9
Comprehensive income (loss)	$ (998)	$ 26,291	$ 10,8

7. New Accounting Principle

In June 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred with the associated asset retirement costs being capitalized as a part of the carrying amount of the long-lived asset. SFAS No. 143 also includes disclosure requirements that provide a description of asset retirement obligations and reconciliation of changes in the components of those obligations. The Company currently records its plugging and abandonment costs, net of salvage value, with respect to its natural gas and oil properties as depreciation, depletion and amortization expense ("DD&A") using the units-of-production method. This statement will require the Company to recognize a liability for the fair value of its plugging and abandonment liability, excluding salvage value, with the associated costs as part of its natural gas and oil property balance. The Company is still evaluating the future financial effects of adopting SFAS No. 143 and will adopt the standard effective January 1, 2003.

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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 future 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 DD&A rate;
- production and reserves concentrated in a small number of properties;
- operating hazards attendant to the natural gas and oil business;
- downhole drilling and completion risks that 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, 2001.

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 at 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. 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.

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 dismantlement, restoration and abandonment costs, net of estimated salvage values.

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, 2002, the Company excluded from the amortization base estimated future expenditures of $27.0 million associated with common development costs for its deep water discovery at 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 $27.0 million had been included in the amortization base as of September 30, 2002, and no additional reserves were assigned to the Front Runner project, the DD&A rate as of September 30, 2002 would have been $2.24 per thousand cubic feet gas equivalent ("Mcfe"). All future development costs associated with the deep water 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 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, 2002, discounted at 10 percent, plus the lower of cost or fair value of unproved properties, as adjusted for related income tax effects (the full cost ceiling). If capitalized costs exceed the full cost ceiling, the excess is charged to write-down of natural gas and oil properties in the quarter in which the excess occurs.

Given 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, 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 General and Administrative Expenses

Under the full cost method of accounting, certain internal costs are capitalized that are directly identified with acquisition, exploration and development activities. These capitalized internal costs include salaries, employee benefits, costs of consulting services and other related expenses and do not include costs related to production, general corporate overhead or similar activities. Spinnaker capitalized $1.4 million and $4.3 million of general and administrative costs in the third quarter and first nine months of 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, wells pending determination and capitalized interest. Unevaluated leasehold costs, delay rentals and capitalized interest 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, delay rentals and capitalized interest 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.

Other

The costs associated with seismic hardware and software are included in other property and equipment. These costs are depreciated using the straight-line method over three years, with the provision for depreciation recorded to the amortization base. Spinnaker capitalized a provision of $0.4 million and $0.9 million related to seismic hardware and software costs in the third quarter and first nine months of 2002, respectively.

Overview

Financial and operational results for the three and nine months ended September 30, 2002 compared to the same periods in 2001 included:

Three Months Ended September 30, 2002 as Compared to the Three Months Ended September 30, 2001

- Production of 14.8 billion cubic feet gas equivalent ("Bcfe"), up 4 percent.

- Revenues of $51.6 million, up 15 percent.
- Income from operations of $11.0 million, down 32 percent.
- Net income of $7.1 million, down 34 percent.
- Cash flows from operating activities, before working capital changes, of $43.5 million, up 11 percent.

Nine Months Ended September 30, 2002 as Compared to the Nine Months Ended September 30, 2001

- Production of 35.2 Bcfe, down 13 percent.
- Revenues of $121.3 million, down 29 percent.
- Income from operations of $29.3 million, down 68 percent.
- Net income of $18.9 million, down 69 percent.
- Cash flows from operating activities, before working capital changes, of $101.7 million, down 36 percent.

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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:

	For the Three Months Ended September 30,		For the Ended S
	2002	2001	2002
Production:			
Natural gas (MMcf)	12,690	13,747	31,13
Oil and condensate (MBbls)	349	81	67
Total (MMcfe)	14,783	14,235	35,16
Revenues (in thousands):			
Natural gas	$ 41,303	$ 39,945	$ 96,75
Oil and condensate	9,058	2,083	16,92
Net hedging income (loss)	1,225	2,465	7,71
Other	(28)	325	(6
Total	$ 51,558	$ 44,818	$ 121,32
Average sales price per unit:			
Natural gas revenues from production (per Mcf)	$ 3.25	$ 2.91	$ 3.1
Effects of hedging activities (per Mcf)	0.10	0.17	0.2
Average price (per Mcf)	$ 3.35	$ 3.08	$ 3.3
Oil and condensate revenues from production (per Bbl)	$ 25.97	$ 25.66	$ 25.2
Effects of hedging activities (per Bbl)	-	-	
Average price (per Bbl)	$ 25.97	$ 25.66	$ 25.2
Total revenues from production (per Mcfe)	$ 3.41	$ 2.95	$ 3.2
Effects of hedging activities (per Mcfe)	0.08	0.18	0.2

Total average price (per Mcfe)	$ 3.49	$ 3.13	$ 3.4
Expenses (per Mcfe):			
Lease operating expenses	$ 0.35	$ 0.23	$ 0.3
Depreciation, depletion and amortization - natural gas and oil properties	$ 2.16	$ 1.62	$ 2.0
Income from operations (in thousands)	$ 11,042	$ 16,150	$ 29,26

Three Months Ended September 30, 2002 as Compared to the Three Months Ended September 30, 2001

Revenues, including the effects of hedging activities, increased $6.7 million in the third quarter of 2002 compared to the third quarter of 2001. The increase in revenues was primarily due to higher oil production in the third quarter of 2002 compared to the third quarter of 2001. Excluding the effects of hedging activities, natural gas revenues increased $1.4 million and oil and condensate revenues increased $7.0 million. The net income associated with hedging activities in the third quarter of 2002 decreased $1.6 million compared to the third quarter of 2001.

Production increased approximately 0.5 Bcfe in the third quarter of 2002 compared to the third quarter of 2001. Average daily production in the third quarter of 2002 was 161 million cubic feet gas equivalent ("MMcfe") compared to 155 MMcfe in the same period of 2001. Natural gas revenues increased $1.4 million due to higher prices in the third quarter of 2002, although natural gas production decreased 1.1 Bcf. Excluding the effects of hedging activities, third quarter 2002 natural gas prices averaged $3.25 per Mcf compared to $2.91 per Mcf in the third quarter of 2001. The production declines of certain producing wells, particularly in the High Island 202 area, resulted in lower natural gas production in the third quarter of 2002. Oil and condensate revenues increased $7.0 million primarily due to higher production volumes of 268 thousand barrels ("MBbls"). Third quarter 2002 oil and condensate prices averaged $25.97 per barrel compared to $25.66 in the same period

of 2001. The Company estimates that its net production was reduced by approximately 0.5 Bcfe in the third quarter of 2002 as a result of Tropical Storms Fay and Isidore. The Company estimates that its net production will be reduced by approximately 0.8 Bcfe in the fourth quarter of 2002 as a result of Hurricane Lili, which caused damage to several pipelines and facilities in which the Company owns an interest.

Lease operating expenses increased $1.9 million in the third quarter of 2002 compared to the third quarter of 2001. Of the total increase in lease operating expenses, approximately $3.0 million was attributable to wells on 11 new blocks that commenced production subsequent to September 30, 2001, offset in part by decreases of $0.6 million in operating expenses associated with existing wells and $0.5 million in workover expenses. The overall increase in the lease operating expense rate per Mcfe in the third quarter of 2002 compared to the same period in 2001 was primarily due to the production declines of certain wells in the High Island 202 area where the lease operating rate was significantly lower than other producing areas operated by the Company.

DD&A increased $8.9 million in the third quarter of 2002 compared to the third quarter of 2001. Of the total increase in DD&A, $8.0 million related to an increase in the DD&A rate per Mcfe and $0.9 million related to higher production volumes in the third quarter of 2002. The DD&A rate increased in the third quarter of 2002 compared to the second quarter of 2002 primarily due to four unsuccessful drilling operations. Because of additional unsuccessful drilling operations experienced to date, the Company currently expects that the DD&A rate will increase in the fourth quarter of 2002 to approximately $2.25 per Mcfe.

General and administrative expenses increased approximately $0.8 million in the third quarter of 2002 compared to the third quarter of 2001. The increase in general and administrative expenses was primarily due to higher employment-related costs resulting from the Company's recent growth in personnel and increased professional services fees.

Interest income decreased $0.5 million in the third quarter of 2002 compared to the third quarter of 2001 primarily due to lower average cash and short-term investment balances and lower interest rates in the third quarter of 2002. Interest expense increased $0.1 million in the third quarter of 2002 compared to the third quarter of 2001 primarily due to higher commitment fees and loan origination fee amortization in the third quarter of 2002.

Income tax provision decreased $2.1 million in the third quarter of 2002 compared to the third quarter of 2001 due to lower earnings in the third quarter of 2002. Income taxes were accrued at a 36 percent effective tax rate in the third quarter of 2002 and 2001.

The Company recognized net income of $7.1 million, or $0.22 per basic share and $0.21 per diluted share, in the third quarter of 2002 compared to net income of $10.8 million, or $0.40 per basic share and $0.38 per diluted share, in the third quarter of 2001.

Nine Months Ended September 30, 2002 as Compared to the Nine Months Ended September 30, 2001

Revenues, including the effects of hedging activities, decreased $50.4 million in the first nine months of 2002 compared to the first nine months of 2001. The decrease in revenues was primarily due to lower natural gas production and prices in the first nine months of 2002. Excluding the effects of hedging activities, natural gas revenues decreased $84.7 million and oil and condensate revenues increased $10.8 million. Revenues from natural gas hedging activities improved approximately $23.5 million in the first nine months of 2002 compared to the same period of 2001.

Production decreased approximately 5.1 Bcfe in the first nine months of 2002 compared to the first nine months of 2001. Average daily production in the first nine months of 2002 was 129 MMcfe compared to 147 MMcfe in the same period of 2001. Natural gas revenues decreased $84.7 million due to lower volumes of 7.7 Bcf and lower prices in the first nine months of 2002. Excluding the effects of hedging activities, natural gas prices averaged $3.11 per Mcf in the first nine months of 2002 compared to $4.67 per Mcf in the same period of 2001. The production declines of certain producing wells, particularly in the High Island 202 area, and less than anticipated results from workovers resulted in lower natural gas production in the first nine months of 2002. Oil and condensate revenues increased $10.8 million primarily due to higher production volumes of 442 MBbls. Oil and condensate prices averaged $25.21 per barrel in the first nine months of 2002 compared to $26.80 in the same period of 2001. The Company estimates that its net production was reduced by approximately 0.5 Bcfe in the third quarter of 2002 as a result of Tropical Storms Fay and Isidore. The Company estimates that its net production will be reduced by approximately 0.8 Bcfe in the fourth quarter of 2002 as a result of Hurricane Lili, which caused damage to several pipelines and facilities in which the Company owns an interest.

Lease operating expenses increased $3.1 million in the first nine months of 2002 compared to the first nine months of 2001. Of the total increase in lease operating expenses, approximately $4.4 million was attributable to wells on 11 new blocks that commenced production subsequent to September 30, 2001, offset in part by a decrease of $1.3 million in operating expenses associated with existing wells. The overall increase in the lease operating expense rate per Mcfe in the first nine months of 2002 compared to the same period in 2001 was primarily due to the production declines of certain wells in the High Island 202 area where the lease operating rate was significantly lower than other producing areas operated by the Company.

DD&A increased $7.2 million in the first nine months of 2002 compared to the first nine months of 2001. Of the total increase in DD&A, $15.2 million related to an increase in the DD&A rate, offset by $8.0 million related to lower production volumes of 5.1 Bcfe in the first nine months of 2002 compared to the same period of 2001. Because of additional unsuccessful drilling operations experienced to date, the Company currently expects that the DD&A rate will increase in the fourth quarter of 2002.

General and administrative expenses increased approximately $1.4 million in the first nine months of 2002 compared to the first nine months of 2001. The increase in general and administrative expenses was primarily due to higher employment-related costs resulting from the Company's recent growth and increased professional services fees.

Interest income decreased $2.4 million in the first nine months of 2002 compared to the first nine months of 2001 primarily due to lower average cash and short-term investment balances and significantly lower interest rates in the first nine months of 2002. Interest expense increased $0.3 million in the first nine months of 2002 compared to the same period of 2001 primarily due to interest on borrowings of $37.0 million in the first quarter of 2002 and higher commitment fees. On April 3, 2002, the Company repaid all of its outstanding borrowings of $37.0 million under the Credit Facility.

Income tax provision decreased $23.5 million in the first nine months of 2002 compared to the first nine months of 2001 due to lower earnings in the first nine months of 2002. Income taxes were accrued at a 36 percent effective tax rate in the first nine months of 2002 and 2001.

The Company recognized 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 compared to net income of $60.7 million, or $2.25 per basic share and $2.14 per diluted share, in the same period of 2001.

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. Capital expenditures in 2001 were $288.8 million. Spinnaker has capital expenditure plans for 2002 totaling approximately $322 million and has incurred capital expenditures of approximately $287.4 million in the first nine months of 2002. During 2001, Spinnaker participated in a significant deep water oil discovery, Front Runner, with a 25 percent non-operator working interest. The Company participated in six consecutive successful wells and sidetracks in testing the reservoirs on these blocks. Spinnaker has incurred capital expenditures associated with Front Runner of $20.3 million in the first nine months of 2002 and inception-to-date expenditures of $49.7 million. The Company expects to incur approximately $103 million in future development costs, including approximately $10 million during the remainder of 2002, $60 million in 2003, $15 million in 2004 and $18 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. Additionally, the rapid production declines of certain producing wells resulted in lower production in the first nine months of 2002. 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.

On April 3, 2002, the Company completed a public offering of 5,750,000 shares of Common Stock at $41.50 per share, including the over-allotment option consisting of 750,000 shares. After payment of underwriting discounts and commissions, the Company received net proceeds of $227.9 million. On April 3, 2002, the Company used a portion of the proceeds from the offering to repay outstanding borrowings of $37.0 million. The remaining net proceeds were invested in short-term high quality investments and are being used to fund a portion of the costs to develop the Company's deep water oil discovery at

Front Runner, to fund a portion of exploration and other development activities and for general corporate purposes, including possible acquisitions of properties or seismic data.

While the Company believes that proceeds from the Common Stock offering, working capital, cash flows from operations and available borrowings under its Credit Facility will be sufficient to meet its capital requirements in the next twelve months, additional debt or equity financing may be required in the future to fund its 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.

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 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 increased $22.2 million to $36.3 million at September 30, 2002 from $14.1 million at December 31, 2001. The components of the increase in cash and cash equivalents include $228.3 million provided by financing activities, $88.5 million provided by operating activities and $294.6 million used in investing activities.

Operating Activities

Net cash provided by operating activities in the first nine months of 2002 decreased 56 percent to $88.5 million primarily due to lower natural gas production and prices. 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. These investments are expected to increase the Company's average daily production in the fourth quarter of 2002 as compared to the first nine months of 2002. However, the Company currently expects that its average daily production in 2003 will decline significantly from the levels it expects to achieve in the fourth quarter of 2002.

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 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 increase of $18.3 million in accounts receivable was primarily related to an increase of $8.7 million in the natural gas and oil revenue accrual at September 30, 2002 due to higher production and commodity prices in September 2002 compared to December 2001 and an increase of $7.4 million in joint interest billing and trade receivables due to higher levels of operated drilling and development activities in the third quarter of 2002 compared to the fourth quarter of 2001. The net decrease of $8.2 million in accounts payable and accrued liabilities was primarily due to the reversal of current deferred taxes of $7.2 million related to the fair value of open derivative contracts at December 31, 2001. In connection with the fair value of open derivative contracts at September 30, 2002, the Company recorded a net deferred tax asset of $3.6 million in other current assets.

Investing Activities

Net cash used in investing activities in the first nine months of 2002 increased 39 percent to $294.6 million compared to the first nine months of 2001. Net oil and gas property capital expenditures were $288.0 million and other property and equipment capital expenditures were $6.6 million.

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 deep water projects relative to the drilling costs on shallower depth shelf projects in the Gulf of Mexico. The Company drilled 22 wells in the first nine months of 2002, 13 of which were successful. In 2001, the Company drilled 35 wells, 19 of which were successful. Since inception and through September 30, 2002, the Company has drilled 116 wells, 69 of which were successful, representing a success rate of 59 percent. Dry hole costs, including associated leasehold costs, were $33.6 million and $63.0 million in the three and nine months ended September 30, 2002, respectively.

The Company has capital expenditure plans for the fourth quarter of 2002 of approximately $35 million. The Company has capital expenditure plans for 2003 totaling approximately $268 million, primarily for costs related to exploration and development programs. The Company does not anticipate any significant abandonment or dismantlement costs in 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. In the first nine months of 2002, the Company incurred acquisition, exploration and development costs of $37.7 million, $160.6 million and $82.5 million, respectively. The costs associated with unproved properties and properties under development not included in the amortization base were $140.3 million as of September 30, 2002 and $102.9 million as of December 31, 2001 and included the following (in thousands):

	As of September 30, 2002	As of December 31, 2001
Leasehold, delay rentals and seismic data	$131,196	$ 92,150
Wells in-progress	4,186	10,112
Wells pending determination	4,044	-
Capitalized interest	372	372
Other	461	247
Total	$140,259	$102,881

Financing Activities

Net cash provided by financing activities of $228.3 million in the first nine months of 2002 included proceeds from the public offering of Common Stock and $37.0 million in proceeds from and subsequent payments on borrowings. The Company received net proceeds of $227.9 million from the offering on April 3, 2002, and used a portion of the proceeds from the offering to repay outstanding borrowings of $37.0 million.

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 or about April 30 and September 30 each year. The banks and Spinnaker also have the option to request one additional re-determination each year. The borrowing base is determined by the banks, in their usual and customary manner, and at their sole discretion. 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 percent 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 Toronto-Dominion Bank's base rate for dollar advances made in the United States or the Federal Funds Rate plus 0.5 percent per annum. The commitment fee rate ranges from 0.3 percent to 0.5 percent, depending on the borrowing base usage. The Credit Facility contains various covenants and restrictive provisions. At September 30, 2002, the Company was in compliance with the covenants and restrictive provisions. As of November 12, 2002, the Company had no outstanding borrowings under the Credit Facility.

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 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. However, these contracts also limit the benefits the Company would realize if prices increase. These financial arrangements are fixed price swap contracts and costless collar arrangements and are 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 percent of its estimated twelve-month production quantities without the prior approval of the risk management committee of the board of directors.

See Note 5 to the Company's Notes to Interim Consolidated Financial Statements (Unaudited) for a discussion of activities involving derivative financial instruments during 2002 and the Company's current commodity price risk management positions in fixed price natural gas swap contracts and natural gas collar arrangements. To calculate the potential effect of the derivative contracts on future revenues, the Company applied NYMEX natural gas forward prices as of September 30, 2002 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 Change in Revenues at Current Prices	Estimated Decrease in Revenues with 10% Decrease in Prices	Estimated Decr in Revenues w 10% Increase Prices
Fixed price swap transactions	$ (12,270)	$ (1,763)	$ (23,016)
Collar arrangements	-	-	-

PART II - OTHER INFORMATION

Item 4. Controls and Procedures

(a) Evaluation of disclosure controls and procedures. Within 90 days before the filing of this quarterly report on Form 10-Q, the Company's principal executive officer and principal financial officer evaluated the effectiveness of the Company's disclosure controls and procedures. Based on the evaluation, the Company's principal executive officer and principal financial officer believe that:

- the Company's disclosure controls and procedures are designed to ensure that information required to be disclosed by the Company in the reports it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms; and

- the Company's disclosure controls and procedures were effective to ensure that material information was accumulated and communicated to the Company's management, including the Company's principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

(b) Changes in internal controls. There have been no significant changes in the Company's internal controls or in other factors that could significantly affect the Company's internal controls subsequent to their evaluation, nor have there been any corrective actions with regard to significant deficiencies or material weaknesses.

Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits

12.1 - Calculation of Ratios of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Dividends

(b) Reports on Form 8-K

A Current Report on Form 8-K dated August 13, 2002 and filed on August 14, 2002 furnished under Item 9. Regulation FD Disclosure the certifications by each of the Chief Executive Officer and the Chief Financial Officer that accompanied the Company's Quarterly Report on Form 10-Q for the period ended June 30, 2002 in accordance with 18 U.S.C. Section 1350.

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, 2002

By: /s/ ROBERT M. SNELL

Robert M. Snell
Vice President, Chief Financial Officer and Secretary

Date: November 12, 2002

By: /s/ JEFFREY C. ZARUBA

Jeffrey C. Zaruba
Vice President, Treasurer and Assistant Secretary

CERTIFICATION OF
PRINCIPAL EXECUTIVE OFFICER
OF SPINNAKER EXPLORATION COMPANY
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT

I, Roger L. Jarvis, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Spinnaker Exploration Company;

2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

    a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;

    b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

    c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

    a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal

controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: November 12, 2002

/s/ ROGER L. JARVIS

Name: Roger L. Jarvis
Title: Chief Executive Officer

CERTIFICATION OF
PRINCIPAL FINANCIAL OFFICER
OF SPINNAKER EXPLORATION COMPANY
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT

I, Robert M. Snell, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Spinnaker Exploration Company;

2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

   c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: November 12, 2002

/s/ ROBERT M. SNELL

Name: Robert M. Snell
Title: Chief Financial Officer

EXHIBIT INDEX

Exhibit Number	Description
12.1 –	Calculation of Ratios of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Dividends