NUEVO ENERGY CO
Form 10-Q
August 13, 2003

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

FORM 10-Q

(Mark One)

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

FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2003

OR

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

FOR THE TRANSITION PERIOD FROM __________________ TO ____________________

COMMISSION FILE NUMBER 1-10537

NUEVO ENERGY COMPANY
(Exact Name of Registrant as Specified in Its Charter)

DELAWARE	76-0304436
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1021 MAIN, SUITE 2100, HOUSTON, TEXAS	77002
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (713) 652-0706

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 [ ]

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Common Stock, par value $.01 per share. Shares outstanding on July 31, 2003: 19,348,430

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Below is a list of terms commonly used in the oil and gas industry.

/d	=	per day
Bbl	=	barrel of crude oil or other liquid hydrocarbons
Bcf	=	billion cubic feet of natural gas
Bcfe	=	billion cubic feet of natural gas equivalent
BOE	=	barrel of oil equivalent, converting gas to oil at the ratio of 6 Mcf of gas to 1 Bbl of oil
BOPD	=	barrel of oil per day
MBbl	=	thousand barrels
Mcf	=	thousand cubic feet of natural gas
MMBbl	=	million barrels of oil or other liquid hydrocarbons
MMcf	=	million cubic feet of natural gas
MBOE	=	thousand barrels of oil equivalent
MMBOE	=	million barrels of oil equivalent

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PART I - FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

NUEVO ENERGY COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(IN THOUSANDS, EXCEPT PER SHARE DATA)
(UNAUDITED)

Quarter Ended

	June 30, 2003	June 30, 2002
Revenues		
Crude oil and liquids	$ 80,818	$ 69,5
Natural gas	13,428	7,9
Other	275	
	94,521	77,4
Costs and Expenses		
Lease operating expenses	42,106	32,4
Exploration costs	317	4
Depletion, depreciation, amortization and accretion	17,709	17,4
General and administrative expenses	6,346	7,2
Loss (gain) on disposition of properties	(4,457)	(15,3
Other	(466)	(2
	61,555	41,9
Operating Income	32,966	35,5
Derivative gain (loss)	(784)	(1
Interest income	224	
Interest expense	(9,034)	(9,2
Loss on early extinguishment of debt	(10,892)	
Dividends on TECONS	(1,653)	(1,6
Income From Continuing Operations Before Income Tax	10,827	24,5
Income Tax Expense		
Current	576	
Deferred	3,639	9,9
	4,215	9,9
Income From Continuing Operations	6,612	14,5
Income from discontinued operations, including gain/loss on disposal, net of income tax	770	1,9
Cumulative effect of a change in accounting principle, net of income tax	--	
Net Income	$ 7,382	$ 16,5
Earnings Per Share:		
Basic		
Income from continuing operations	$ 0.34	$ 0.
Income from discontinued operations, net of income tax	0.04	0.
Cumulative effect of a change in accounting principle, net of income tax	--	
Net income	$ 0.38	$ 0.
Diluted		
Income from continuing operations	$ 0.34	$ 0.
Income from discontinued operations, net of income tax	0.04	0.
Cumulative effect of a change in accounting principle, net of income tax	--	
Net income	$ 0.38	$ 0.

Weighted Average Shares Outstanding:		
Basic	19,260	17,0
Diluted	19,507	17,2

See accompanying notes.

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NUEVO ENERGY COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
(IN THOUSANDS, EXCEPT SHARE AMOUNTS)

ASSETS

Current assets
- Cash and cash equivalents
- Accounts receivable, net
- Inventory
- Assets held for sale
- Deferred income taxes
- Prepaid expenses and other

Total current assets

Property and equipment, at cost
- Land
- Oil and gas properties (successful efforts method)
- Other property

Accumulated depreciation, depletion and amortization

Total property and equipment, net

Deferred income taxes
Goodwill
Other assets

Total assets

LIABILITIES AND STOCKHOLDERS' EQUITY

Current liabilities
- Accounts payable
- Accrued interest
- Accrued drilling costs
- Accrued lease operating costs
- Price risk management activities
- Other accrued liabilities

Total current liabilities

Long-term debt
- Senior subordinated notes

Bank credit facility......................	
Total debt......................	
Interest rate swaps - fair value adjustment......................	
Interest rate swaps - termination gain......................	
Long-term debt......................	
Asset retirement obligation......................	
Other long-term liabilities......................	
Company-Obligated Mandatorily Redeemable Convertible Preferred Securities of Nuevo Financing I (TECONS)......................	
Commitments and contingencies (Note 9)	
Stockholders' equity	
Preferred stock, $1.00 par value, 10,000,000 shares authorized; 7% cumulative convertible preferred stock, none issued......................	
Common stock, $0.01 par value, 50,000,000 shares authorized, 23,082,067 and 23,048,388 shares issued and 19,303,020 and 19,110,102 shares outstanding, respectively......................	
Additional paid-in capital......................	
Treasury stock, at cost, 3,779,047 and 3,867,691 shares, respectively......................	
Deferred stock compensation and other......................	
Accumulated other comprehensive income (loss)......................	
Accumulated deficit......................	
Total stockholders' equity......................	
Total liabilities and stockholders' equity......................	

See accompanying notes.

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NUEVO ENERGY COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(IN THOUSANDS)
(UNAUDITED)

	Quarter Ended June 30,	
	2003	2002
Cash flows from operating activities		
Net income	$ 7,382	$ 16,566
Adjustments to reconcile net income to net cash provided by operating activities		
Depletion, depreciation, amortization and accretion......	17,709	17,458
Amortization of debt financing costs....................	548	664
Loss on early extinguishment of debt....................	10,892	--
Net gain on sales of assets............................	(4,457)	(15,326)
Deferred income taxes..................................	3,639	9,948
Non-cash effect of discontinued operations..............	461	3,515
Cumulative effect of a change in accounting principle....	--	--
Other...	988	407
Working capital changes, net of non-cash transactions		

Accounts receivable	11,467	40
Accounts payable	23	(4,751)
Accrued liabilities	(17,835)	(9,099)
Other	7,122	(2,737)
Net cash provided by operating activities	37,939	16,685
Cash flows from investing activities		
Additions to oil and gas properties	(14,641)	(12,991)
Additions to other properties	(1,072)	(1,193)
Proceeds from sale of properties	4,457	24,856
Other investing activities	--	--
Net cash provided by (used in) investing activities	(11,256)	10,672
Cash flows from financing activities		
Payments of long-term debt	(159,577)	--
Premium paid for redemption of notes	(7,505)	--
Net borrowings/repayments of credit facility	66,150	(31,175)
Proceeds from exercise of stock options	781	470
Other proceeds	--	1,294
Net cash used in financing activities	(100,151)	(29,411)
Increase (decrease) in cash and cash equivalents	(73,468)	(2,054)
Cash and cash equivalents		
Beginning of period	73,843	2,299
End of period	$ 375	$ 245

See accompanying notes.

NUEVO ENERGY COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(IN THOUSANDS)
(UNAUDITED)

	Quarter Ended June 30,	
	2003	2002
Net income	$ 7,382	$ 16,566
Unrealized gains (losses) from cash flow hedging activity:		
Reclassification adjustment for settled contracts	4,013	1,195

Changes in fair value of derivative instruments during the period	(5,419)	(2,829
Other comprehensive income (loss)	(1,406)	(1,634
Comprehensive income (loss)	$ 5,976	$ 14,932

See accompanying notes.

NUEVO ENERGY COMPANY
NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. BASIS OF PRESENTATION

Our 2002 Annual Report on Form 10-K includes a summary of our significant accounting policies and other disclosures. You should read it in conjunction with this Quarterly Report on Form 10-Q. The financial statements as of June 30, 2003, and for the three and six months ended June 30, 2003 and 2002, are unaudited. The balance sheet as of December 31, 2002, is derived from the audited balance sheet included in our Form 10-K. These financial statements have been prepared pursuant to the rules and regulations of the U.S. Securities and Exchange Commission ("SEC") and do not include all disclosures required on an annual basis by accounting principles generally accepted in the United States. In our opinion, we have made all adjustments, all of which are of a normal, recurring nature, to fairly present our interim period results. Information for interim periods may not necessarily indicate the results of operations for the entire year.

Our accounting policies are consistent with those discussed in our Form 10-K, except as discussed below. You should refer to our Form 10-K for a further discussion of those policies.

Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity.

In May 2003, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity. SFAS No. 150 establishes standards for how an issuer classifies and measures three classes of freestanding financial instruments (mandatorily redeemable instruments, instruments with repurchase obligations, instruments with obligations to issue a variable number of shares) with characteristics of both liabilities and equity. Instruments within the scope of the statement must be classified as liabilities on the balance sheet. SFAS No. 150 is effective for all freestanding financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. We have not entered into any financial instruments within the scope of SFAS No. 150 since May 31, 2003, nor do we currently hold any significant financial instruments within the scope. SFAS No. 150 does not apply to convertible bonds, consequently our TECONS are not within the scope of SFAS No. 150.

Accounting for Asset Retirement Obligations.

In August 2001, the FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations. This Statement requires a liability to be recorded relating to the eventual retirement and removal of assets used in our business. The liability is discounted to its present value, with a corresponding increase to the related asset value. Over the life of the asset, the liability will be accreted to its future value and eventually extinguished when the asset is taken out of service. The provisions of this statement are effective for fiscal years beginning after June 15, 2002. We adopted the provisions of SFAS No. 143 on January 1, 2003 to record our asset retirement obligation to plug and abandon oil and gas wells. In connection with the initial application of SFAS No. 143, we recorded a cumulative effect of change in accounting principle, net of taxes, of $8.5 million as an increase to net income. In addition, we recorded an asset retirement obligation for oil and gas properties and equipment of $92.7 million. The following table summarizes asset retirement obligation transactions recorded in accordance with the provisions of SFAS No. 143:

	Quarter Ended June 30, 2003	Six Months Ended June 30, 2003
	(In thousands)	
Beginning asset retirement obligation...........	$ 96,902	$ 92,6
Liabilities incurred during period.............	101	2,5
Liabilities settled during period..............	(70)	(5
Accretion expense..............................	2,296	4,5
Ending asset retirement obligation.............	$ 99,229	$ 99,2

In addition, pro forma net income and earnings per share for the quarter ended June 30, 2002 and for the six months ended June 30, 2002 for the change in accounting had SFAS No. 143 been implemented during these periods would have been as follows:

	Quarter Ended June 30, 2002	Six Months En June 30, 200
	(In thousands, except per share data)	
Net income		
As Reported................................	$ 16,566	$ 18,028
Pro Forma..................................	17,646	20,359
Net income per share - Reported		
Basic......................................	0.97	1.06
Diluted....................................	0.96	1.05
Net income per share - Pro Forma		
Basic......................................	1.03	1.19
Diluted....................................	1.02	1.18

Guarantor's Accounting and Disclosure Requirements.

The FASB issued Interpretation No. 45 ("FIN 45"), Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of the Indebtedness of Others, in November 2002, which clarifies the requirements of SFAS No. 5, Accounting for Contingencies, relating to a guarantor's accounting for and disclosures of certain guarantees issued. FIN 45 requires enhanced disclosures for certain guarantees. It also requires that certain guarantees issued or modified after December 31, 2002, including certain third-party guarantees, be recorded initially on the balance sheet at fair value. For guarantees issued on or before December 31, 2002, liabilities are recorded when and if payments become probable and estimable. We adopted FIN 45 effective January 1, 2003, and have included the disclosure requirements of FIN 45 in Note 9 to the condensed consolidated financial statements. The adoption of FIN 45 did not have a material effect on our consolidated financial position, results of operations or cash flows.

Consolidation of Variable Interest Entities.

In January 2003, the FASB issued Interpretation No. 46 ("FIN 46"), Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51. FIN 46 requires certain variable interest entities, or VIEs, to be consolidated by the primary beneficiary of the entity if the equity investors in the entity do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. FIN 46 is effective for all VIEs created or acquired after January 31, 2003. For VIEs created or acquired prior to February 1, 2003, the provisions of FIN 46 must be applied for the first interim or annual period beginning after June 15, 2003. We currently have no contractual relationship or other business relationship with a variable interest entity and therefore the adoption of FIN 46 had no effect on our consolidated financial position, results of operations or cash flows.

Accounting for Costs Associated with Mineral Rights.

The FASB and representatives of the accounting staff of the SEC are currently engaged in discussions regarding the application of certain provisions of SFAS No. 141, Business Combinations, and SFAS No. 142, Goodwill and Other Intangible Assets, with companies in the extractive industries, including oil and gas companies. The FASB and the SEC staff are considering whether the provisions of SFAS No. 141 and SFAS No. 142 require registrants to classify costs associated with mineral rights, including both proved and unproved lease acquisition costs, as intangible assets on the balance sheet, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures.

Consistent with industry practice, we historically have included oil and gas lease acquisition costs as a component of oil and gas properties pursuant to the provisions of SFAS 19, Financial Accounting and Reporting by Oil and Gas Producing Companies. In the event the FASB and SEC staff determine that costs associated with mineral rights are required to be classified as intangible assets, a substantial portion of our oil and gas property acquisition costs since the June 30, 2001 effective date of SFAS Nos. 141 and 142 would be separately classified on the balance sheets as intangible assets. However, the results of operations would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with successful efforts accounting rules. The classification of oil and gas lease acquisition costs as intangible assets would not have any impact on our compliance with covenants under our debt agreements.

2. STOCK-BASED COMPENSATION

We account for stock compensation plans under the intrinsic value method of Accounting Principles Board Opinion ("APB") No. 25, Accounting for Stock Issued to Employees. No compensation expense is recognized for stock options that had an exercise price equal to or greater than the market value of the underlying common stock on the date of grant. As permitted by SFAS No. 123, Accounting for Stock-Based Compensation, we have continued to apply APB Opinion No. 25 for purposes of determining net income. Had compensation expense for stock-based compensation been determined based on the fair value at the date of grant, our net income and earnings per share would have been as follows:

	Quarter Ended June 30, 2003	2002	Six Mo 2003
	(In thousands, except per shar		
Net income as reported..........................	$ 7,382	$ 16,566	$ 33,
Add:			
Stock based employee compensation expense included in reported net income, net of related income tax..........................	310	155	
Deduct:			
Total stock based employee compensation expense determined under fair value based method for all awards, net of related income tax.................................	(565)	(297)	(1,
Pro forma net income...........................	$ 7,127	$ 16,424	$ 32,
Earnings per share:			
Basic - as reported.........................	$ 0.38	$ 0.97	$ 1
Basic - pro forma...........................	0.37	0.96	1
Diluted - as reported.......................	$ 0.38	$ 0.96	$ 1
Diluted - pro forma.........................	0.37	0.95	1

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3. EARNINGS PER SHARE

SFAS No. 128, Earnings per Share, requires a reconciliation of the numerator (income) and denominator (shares) of the basic earnings per share computation to the numerator and denominator of the diluted earnings per share computation. The reconciliation is as follows:

Quarter Ended June 30,

	2003		200
	Net Income	Shares	Net Income
	(In thousands)		
Earnings - Basic........................	$ 7,382	19,260	$ 16,566
Effect of dilutive securities			
Stock options and restricted stock...	--	247	--
Shares held by benefit trust.........	--	--	29
Earnings - Diluted......................	$ 7,382	19,507	$ 16,595

	Six Months Ended June 30,		
	2003		200
	Net Income	Shares	Net Income
	(In thousands)		
Earnings - Basic........................	$ 33,095	19,230	$ 18,028
Effect of dilutive securities			
Stock options and restricted stock...	--	216	--
Shares held by benefit trust.........	--	--	(8)
Earnings - Diluted......................	$ 33,095	19,446	$ 18,020

4. DISCONTINUED OPERATIONS

We sold our Eastern properties in 2002 and we sold our Brea-Olinda and Union Island oil and gas properties in 2003. Also, in the first quarter 2003, our Board approved the sale of our Orcutt Hill oil and gas property. The historical results of operations of these properties are classified as discontinued operations in our statements of income. The following table reflects revenue, gain/loss on disposition and pre-tax income for the periods presented:

	Quarter Ended June 30,		Six Months End
	2003	2002	2003
	(In thousands)		
Brea-Olinda			
Revenue.............................	$ 1	$ 4,122	$ 3,246
Gain/(Loss) on disposition...........	--	--	--
Pre-tax income......................	244	2,153	2,843
Union Island			
Revenue.............................	71	241	1,575
Gain/(Loss) on disposition...........	(20)	--	7,705

Pre-tax income......................	68	28	9,118
Eastern Properties			
Revenue.............................	--	1,767	--
Gain/(Loss) on disposition..........	--	(84)	--
Pre-tax income......................	--	422	--
Orcutt Hill			
Revenue.............................	2,337	2,263	5,075
Gain/(Loss) on disposition..........	--	--	(5,350)
Pre-tax income......................	981	727	(3,081)

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5. ACQUISITION OF ATHANOR RESOURCES, INC.

We acquired Athanor Resources, Inc. ("Athanor") in September 2002 for $61.3 million in cash, the issuance of approximately $20.1 million of our common stock (approximately 2.0 million shares) and the assumption of net liabilities with a fair value of approximately $20.0 million. The acquisition was accounted for using the purchase method of accounting. In the second quarter of 2003, we finalized our purchase price allocation, and adjusted certain assets and liabilities to reflect $2.5 million in insurance proceeds received related to a pre-acquisition claim. As of June 30, 2003, $17.1 million of goodwill is reflected on our balance sheet related to Athanor.

The following unaudited pro forma condensed income statement information has been prepared to give effect to the merger as if the transaction had occurred at the beginning of the period presented. The historical results of operations, based on 2002 realized prices, have been adjusted to reflect the difference between Athanor's historical depletion, depreciation and amortization and the expense calculated based on the value allocated to the assets acquired in the merger. The information presented is not necessarily indicative of the results of future operations of the merged companies.

	Quarter Ended June 30, 2002	Six Mon June 3
	(In thousands, except per shar	
Revenues..	$ 83,263	$ 158
Income from continuing operations......................	15,511	16
Net income..	17,490	19
Earnings per share		
Basic		
Income from continuing operations...............	$ 0.81	$
Net income	0.92	
Diluted		
Income from continuing operations...............	$ 0.81	$
Net income	0.91	

6. LONG-TERM DEBT

Our long-term debt consists of the following:

	June 30, 2003
	(In thousa
9 3/8% Senior Subordinated Notes due 2010	$ 150,000
9 1/2% Senior Subordinated Notes due 2008	100,000
9 1/2% Senior Subordinated Notes due 2006	--
Bank credit facility (2.36% June 30, 2003, 3.11% December 31, 2002)........	66,150
Total debt...	316,150
Interest rate swaps - fair value adjustment................................	--
Interest rate swaps - termination gain...................................	15,180
Long-term debt...	$ 331,330

In April 2003, we called and completed the redemption of our 9 1/2% Senior Subordinated Notes due 2006. The notes were redeemed at 101.58% per note. In June 2003, we called and completed the redemption of $157.2 million of our 9 1/2% Senior Subordinated Notes due 2008 at 104.75% per note. In the second quarter of 2003, we recorded a $10.9 million loss on early extinguishment of debt consisting of a $7.5 million call premium and a $3.4 million deferred financing cost write-off on the notes called. We also terminated our interest rate swaps and received cash of $4.1 million during the second quarter 2003 (See Note 7).

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7. FINANCIAL INSTRUMENTS

We have entered into commodity swaps, collars, put options and interest rate swaps. The commodity swaps, collars and put options are designated as cash flow hedges and the interest rate swaps are designated as fair value hedges in accordance with SFAS No. 133. Quantities covered by the commodity swaps and put options are based on West Texas Intermediate ("WTI") barrels. The selling price for our production is expected to average 74% of WTI, therefore, each WTI barrel hedges 1.36 barrels of our production.

Derivative Instruments Designated as Cash Flow Hedges

At June 30, 2003, we had entered into the following cash flow hedges:

	Crude Oil			Natu
	Bbls / day	$ / Bbl	Index	MMbtu/day
Swaps for Sales				
2003				
3rd Qtr.............	13,500	$ 23.62	WTI	7,500
4th Qtr.............	13,500	23.79	WTI	8,000
2004				
1st Qtr.............	14,500	23.76	WTI	16,500

2nd Qtr.............	13,500	24.03	WTI	14,500
3rd Qtr.............	11,000	23.64	WTI	10,500
4th Qtr.............	6,500	23.23	WTI	14,500
2005				
Full Year...........	4,500	22.14	WTI	
Collars				
2003				
Full Year...........	10,000	22.00-28.91	WTI	
3rd Qtr.............				6,000
4th Qtr.............				6,000
Swaps for Purchases				
2004................				8,000
2005................				8,000

Derivative Instruments Designated as Fair Value Hedges.

In late December 2001 and early 2002, we entered into three interest rate swap agreements with notional amounts totaling $200.0 million to hedge the fair value of our 9 1/2% Notes due 2008 and our 9 3/8% Notes due 2010. These swaps were designated as fair value hedges and were reflected as an increase or decrease of long-term debt with a corresponding increase in long-term assets or liabilities.

In late August and early September 2002, we terminated our swap transactions relating to these Notes. As a result of these terminations, we received accrued interest of $2.2 million and the present value of the swap option of $9.6 million on our 9 3/8% Notes and $0.5 million in accrued interest and the present value of the swap option of $2.5 million on our 9 1/2% Notes. The gain of $9.6 million on our 9 3/8% Notes and $2.5 million on our 9 1/2% Notes is reflected as an increase of long-term debt and is being amortized as a periodic reduction in interest expense over the life of the Notes. During the three months ended June 30, 2003, we amortized $0.3 million as a reduction of interest expense.

Following the termination of the three interest rate swaps referenced above, in late August and early November 2002, we entered into two new interest rate swap agreements with notional amounts totaling $100.0 million, to hedge a portion of the fair value of our 9 3/8% Notes due 2010. These swaps were designated as fair value hedges and were reflected as an increase of long-term debt with a corresponding increase in long-term assets.

In May 2003, we terminated our swap transactions relating to these Notes. As a result of these terminations, we received accrued interest of $0.4 million and the present value of the swap option of $4.1 million. The gain of $4.1 million on the Notes is reflected as an increase of long-term debt and is being amortized as a periodic reduction in interest expense over the life of the Notes. During the three months ended June 30, 2003, we amortized $0.2 million as a reduction of interest expense. We currently have no interest rate swaps in place.

Other - Call Spreads.

We have a call spread that is not designated as a hedging instrument and is marked-to-market with changes in fair value recognized currently as a derivative gain/loss. During the three months ended June 30, 2003 we recorded a $0.8 million derivative loss and recorded the fair value of the remaining derivative loss at June 30, 2003 totaling $4.5 million in accrued liabilities.

8. SEGMENTS

Our operations consist of the acquisition, exploitation, exploration, development and production of crude oil and natural gas. Our reportable segments are domestic, foreign and other. Financial information by reportable segment is presented below:

	For the Quarter Ended June 30,		
	Oil and Gas Domestic	Oil and Gas Foreign(1)	Other(2)
	(In thousands)		
Revenues from external customers.............	$ 79,809	$ 14,437	$ 27
Operating income (loss) before income tax....	29,386	9,493	(28,05

	For the Quarter Ended June 30,		
	Oil and Gas Domestic	Oil and Gas Foreign(1)	Other(2)
	(In thousands)		
Revenues from external customers.............	$ 69,205	$ 8,244	$ 4
Operating income (loss) before income tax....	39,386	3,800	(18,65

	For the Six Months Ended June 30		
	Oil and Gas Domestic	Oil and Gas Foreign(1)	Other(2)
	(In thousands)		
Revenues from external customers.............	$ 166,440	$ 25,918	$ 41
Operating income (loss) before income tax....	64,688	15,143	(47,89

	For the Six Months Ended June 30		
	Oil and Gas Domestic	Oil and Gas Foreign(1)	Other(2)
	(In thousands)		
Revenues from external customers.............	$ 132,743	$ 15,668	$ 4
Operating income (loss) before income tax....	55,696	6,144	(36,68

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(1) The timing of Congo crude oil liftings has a significant effect on foreign results of operations.
(2) Includes corporate income and expenses.

9. COMMITMENTS AND CONTINGENCIES

Legal Proceedings and Other Matters

We acquired properties from Unocal and are obligated to make a contingent payment based on net proceeds received, less certain deductions, on oil sold through 2004 if oil prices exceed thresholds set forth in the agreement with Unocal. Contingent payments are accounted for as a purchase price adjustment to oil and gas properties. We paid $10.8 million to Unocal in 2002 attributable to calendar year 2001 and recorded the payment in oil and gas properties. In March 2003, we advised Unocal that we had failed to take deductions to the sales price that we believe are permitted by the agreement. Application of these deductions results in no payment due for either calendar year 2001 or 2002. Unocal disputes this position for both years. Attempts to resolve this issue through mediation were unsuccessful. We filed suit against Unocal to recover the 2001 payment, and secure a declaration of the appropriate deduction methodology to be applied for 2002 through 2004 and to recover attorneys' fees. Unocal has answered and filed a counterclaim claiming breach of contract and anticipatory breach of contract seeking $16.0 million for 2002 and a declaration of the appropriate deduction methodology and attorneys' fees. While the outcome of this matter is not presently determinable, its resolution is not expected to have a significant impact on our results of operations, financial condition or liquidity.

We have asserted a claim against Torch Energy Advisors for matters arising out of our former outsourcing arrangement. Among other demands, we have requested the return of a $2.0 million working capital advance. Torch has asserted claims for indemnity and payment of certain fees it asserts are owed to them. These outstanding issues will be arbitrated and are not expected to have a material impact on our operating results, financial condition or liquidity.

During the second quarter 2003, we entered into a settlement agreement with Hills for Everyone, a non-profit organization, and Orange County, California ending litigation challenging the adequacy of the environmental review of our Tonner Hills real estate project. The settlement did not have a material impact on the project or our operating results, financial condition or liquidity.

Contingencies

June 2001, we experienced a failure of a carbon dioxide treatment vessel at the Rincon Onshore Separation Facility ("ROSF") located in Ventura County, California. There were no injuries associated with this event. Crude oil and natural gas produced from three fields offshore California are transported onshore by pipeline to the ROSF plant where crude oil and water are separated and treated, and carbon dioxide is removed from the natural gas stream. The daily net production associated with these fields was 3,000 barrels of crude oil and 2.4 MMcf of natural gas in 2001, representing approximately 6% of our daily production. In early July 2001, crude oil production resumed and full gas sales resumed by mid August 2001. Insurance claims relating to the cost of repair and business interruption (less a 30-day waiting period) were settled in the second quarter 2003 and we recognized income of $2.3 million.

In September 1997, there was a spill of crude oil into the Santa Barbara Channel from a pipeline that connects our Point Pedernales field with shore-based processing facilities. As of June 30, 2003, all outstanding claims have been settled and compromised. We are awaiting final disposition of certain non-material insurance claims that have been submitted to our carriers.

Our 1994 acquisition agreement to purchase the two subsidiaries owning interests in the Yombo field offshore Congo contains a provision for contingent purchase consideration to be paid by us to the seller if certain conditions are met. If we recover from sales of production up to an amount greater than all of our capital and operating costs plus $27 million and which amount increases 27% annually, then we will pay to the seller out of one-half of our sales proceeds from the sale of our production, an amount equal to $2.8 million, increased by 7% per year from 1995. We currently estimate that we could reach payout as early as 2005.

Guarantees Related to Assets or Obligations of Third Parties

We have indemnified certain third parties for future environmental remediation costs that may be incurred for properties that we purchased or properties that we sold to a third party. The properties may or may not require environmental remediation and if we are determined to be responsible, our indemnities may require us, among other matters, to pay for the remediation costs. We are not able to determine the maximum potential amount, if any, of future payments that we could be required to make under these indemnifications primarily due to the following: the indefinite term of the majority of these indemnities; the unknown extent of possible contamination; the conditional nature of our responsibility under certain indemnities; uncertainties related to the timing of the remediation work; possible changes in laws governing the remediation process; the unknown number of claims that may be made and changes in remediation technology.

We have performance obligations in the ordinary course of business that are secured by surety bonds or letters of credit. These surety bonds and letters of credit are issued by financial institutions and are required to be reimbursed if drawn upon. At June 30, 2003, we had surety bonds of $39.7 million and letters of credit of $2.2 million.

In the ordinary course of business, we have provided indemnifications and guarantees that are not explicitly defined whose terms range in duration. We do not believe that these will have a material effect on our financial position, results of operation or cash flows.

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our discussion and analysis of our financial condition and results of operations is based upon our consolidated financial statements which have been prepared in accordance with accounting principles generally accepted in the

United States of America ("GAAP"). The preparation of our financial statements requires us to make estimates and judgments that affect the reported amount of assets, liabilities, revenues and expenses. We believe the following critical accounting policies reflect our significant estimates and judgments used in the preparation of our financial statements:

Revenue Recognition. Crude oil and natural gas revenue is recognized when title passes to the purchaser. We use the entitlement method for recording sales of crude oil and natural gas from producing wells. Under the entitlement method, revenue is recorded based on our net revenue interest in production. Deliveries of crude oil and natural gas in excess of our net revenue interests are recorded as liabilities and under-deliveries are recorded as assets. Production imbalances are recorded at the lower of the sales price in effect at the time of production or the current market value. Substantially all such amounts are anticipated to be settled with production in future periods.

Successful Efforts Accounting. We account for our crude oil and natural gas operations using the successful efforts method of accounting. Under this method of accounting, all costs associated with oil and gas lease acquisition costs, successful exploratory wells and all development wells are capitalized and amortized on a unit-of-production basis over the remaining life of proved developed reserves and proved reserves. When a proved property is sold, ceases to produce or is abandoned, a gain or loss is recognized. When an entire interest in an unproved property is sold for cash or cash equivalent, a gain or loss is recognized, taking into consideration any recorded impairment. When a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained. Unproved leasehold costs are capitalized pending the results of exploration efforts. Exploration costs, including geological and geophysical expenses, exploratory dry holes and delay rentals, are charged to expense when incurred.

Proved Reserve Estimates. There are uncertainties inherent in estimating crude oil and natural gas reserve quantities, projecting future production rates and projecting the timing of future development expenditures. In addition, reserve estimates of new discoveries are more imprecise than those of properties with a production history. Accordingly, these estimates are subject to change as additional information becomes available. Proved reserves are the estimated quantities of crude oil, condensate and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions at the end of the respective years. Proved developed reserves are those reserves expected to be recovered through existing equipment and operating methods.

Impairment of Proved Oil and Gas Properties. We review our proved properties when management determines that events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. If the carrying amount of an asset exceeds the sum of the undiscounted estimated future net cash flows, we recognize an impairment equal to the difference between the carrying value and the fair value of the asset which is estimated to be the expected present value of future net cash flows from proved reserves, utilizing a risk-free rate of return.

Impairment of Unproved Oil and Gas Properties. Unproved leasehold costs are reviewed periodically and a loss is recognized to the extent, if any, that the cost of the property has been impaired.

Impairment of Goodwill. Goodwill of a reporting unit is tested for impairment annually in the fourth quarter, and also at interim dates upon the occurrence of significant events. The fair value of each reporting unit that has goodwill is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, including goodwill, the fair value of the reporting unit's individual assets and liabilities is deducted from the fair value of the reporting unit. This difference represents the implied fair value of goodwill, which is compared to the book value of the reporting unit's goodwill. We recognize an impairment of the excess of the book value of goodwill over the implied fair value of goodwill.

Asset Retirement Obligations. The computation of asset retirement obligations was prepared in accordance with SFAS No. 143, Accounting for Asset Retirement Obligation, which requires us to record the fair value of liabilities for retirement obligations of long-lived assets. Our asset retirement obligations arise from the plugging and abandonment liabilities for our oil and gas wells and offshore platform facilities. We estimated our liability based on the best information available to us at this time. Revisions to the liability could occur due to changes in the timing and actual plugging and abandonment costs.

Derivative Financial Instruments and Price Risk Management Activities. We use price risk management activities to manage non-trading market risks. We use derivative financial instruments such as swaps, collars and put options to hedge the impact market price risk exposures on our crude oil and natural gas production, natural gas purchases and to mitigate our exposure to interest rate risk. We account for our derivatives under SFAS 133, Accounting for Derivative Instruments and Hedging Activities, and have elected to designate derivative instruments that qualify for hedge accounting as cash flow hedges for commodity related contracts and fair value hedges for interest rate contracts. Derivatives that do not qualify for hedge accounting are carried on the balance sheet at fair value, and changes in its fair value are recognized in earnings.

Stock-Based Compensation. We account for stock compensation plans under the intrinsic value method of Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees. No compensation expense is recognized for stock options that had an exercise price equal to their market value of the underlying common stock on the date of grant. We disclose in both annual and interim financial statements the effect of reported results had the stock based compensation been determined based on fair value at the date of grant and expensed.

Income Taxes. Deferred income taxes are accounted for under the asset and liability method of accounting for income taxes. Under this method, deferred income taxes are recognized for the tax consequences of temporary differences by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. The effect on deferred taxes of a change in tax rates is recognized in income in the period the change occurs.

RESULTS OF OPERATIONS

Our results of operations are significantly affected by fluctuations in oil and gas prices. We sold our Brea-Olinda field, Union Island field, Eastern properties and our Orcutt Hill field is held for sale. The results of operations of these properties are classified as discontinued operations in our financial statements. The following table reflects our production and average prices for oil and natural gas excluding our discontinued operations for all periods presented:

	Quarter Ended June 30,		Six Months June 30
	2003	2002	2003
Crude Oil and Liquids			
Sales Volumes (MBbls/day)			
Domestic	37.1	35.9	37.1
Foreign	5.0	5.4	5.0
Total	42.1	41.3	42.1
Sales Prices ($/Bbl)			
Unhedged	$ 22.68	$ 19.05	$ 24.09
Hedged	21.09	18.47	21.46
Revenues ($/thousands)			
Domestic	$ 72,480	$ 63,675	$ 157,751
Foreign	14,437	8,244	25,918
Marketing Fees	(1)	(253)	(4)
Hedging	(6,098)	(2,160)	(20,045)
Total	$ 80,818	$ 69,506	$ 163,620

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	Quarter Ended June 30,		Six Months June 30
	2003	2002	2003
Natural Gas			
Sales Volumes (MMcf/day)			
Domestic	36.4	28.1	37.9
Sales Prices ($/Mcf)			
Unhedged	$ 4.26	$ 3.10	$ 4.54
Hedged.......................	4.06	3.10	4.19
Revenues ($/thousands)			
Domestic	$ 14,250	$ 8,092	$ 31,356
Marketing Fees	(153)	(149)	(246)
Hedging......................	(669)	--	(2,372)
Total	$ 13,428	$ 7,943	$ 28,738

QUARTER ENDED JUNE 30, 2003 COMPARED TO QUARTER ENDED JUNE 30, 2002

We had net income of $7.4 million, or $0.38 per diluted share and income from continuing operations was $6.6 million, or $0.34 per diluted share for the quarter ended June 30, 2003 as compared to net income of $16.6 million, or $0.96 per diluted share and income from continuing operations of $14.6 million, or $0.84 per diluted share in the same period of 2002. Income from continuing operations is discussed below.

Revenues

Oil and Gas Revenues. Oil and gas revenues increased 22% to $94.2 million for the three months ended June 30, 2003 from $77.4 million in the same period of 2002 due to higher realized crude oil and natural gas prices and higher natural gas production which was partially offset by higher hedging losses in 2003. Crude oil production increased to 42.1 MBbls/day for the three months ended June 30, 2003 compared to 41.3 MBbls/day in the same period of 2002 primarily due to higher production from the Pakenham field which was acquired in September 2002 and the acquisition of an additional interest in the Point Pedernales field offshore California. The realized oil price for the three months ended June 30, 2003 was $21.09 per Bbl, an increase of $2.62 per Bbl from the same period in 2002. We had crude oil hedging losses of $6.1 million in the three months ended June 30, 2003 compared to hedging losses of $2.2 million in same period of 2002. Natural gas production averaged 36.4 MMcf per day for the three months ended June 30, 2003, an increase of 8.3 MMcf per day from the same period of 2002. The Pakenham field which was acquired in September 2002 averaged 14.8 MMcf per day during the three months ended June 30, 2003 and was partially offset by lower production onshore and offshore California of 6.6 MMcf per day due to the watering out of wells on our Pitas Point offshore property (3.9 MMcf per day) and mechanical downtime and normal declines on other California properties. The realized natural gas price for the three months ended June 30, 2003 increased 31% to $4.06 per Mcf, including a $0.20 per Mcf hedging loss, compared to $3.10 per Mcf from the comparable period in 2002 that had no gas hedged.

Costs and Expenses

Costs and Expenses. Lease operating expense ("LOE") for the three months ended June 30, 2003 totaled $42.1 million, as compared to $32.4 million for the 2002 period. The increased LOE is due to higher steam costs in our onshore California operations (principally due to higher natural gas prices for gas purchased), higher workover and major maintenance expense in our offshore California operations and field costs in our Pakenham field which was purchased in 2002 and the acquisition of an additional interest in Point Pedernales. Although depletion, depreciation, amortization and accretion ("DD&A") of $17.7 million for the three months ended June 30, 2003, was comparable to the same period of 2002, the DD&A rate was $4.04 per BOE in the 2003 period compared to $4.17 per BOE in 2002. General and administrative expense of $6.3 million in 2003 was $0.9 million lower than the comparable period in 2002 primarily due to lower outsourcing costs in 2003. The gain on disposition of properties was $4.5 million for the three months ended June 30, 2003 as compared to a $15.3 million gain in 2002. The 2003 gain was due to the release of escrow related to the sale of properties in 2001. In

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2002, under the terms of a settlement agreement with ExxonMobil, we conveyed to them our interest in the Santa Ynez Unit, our non-consent interest in the adjacent Pescado field and relinquished our right to participate in the Sacate field and recorded a $14.7 million gain related to the sale of this unproved property.

Derivative Gain (Loss). Our derivative loss for the quarter ended June 30, 2003 was $0.8 million compared to a loss of $0.2 million in the same period of 2002. The derivative loss is comprised of a loss on our mark-to-market derivatives and ineffectiveness of our hedges.

Interest Expense. Interest expense was $9.0 million for the three months ended June 30, 2003 compared to interest expense of $9.2 million in the same period of 2002. Lower interest expense on the line of credit of $0.5 million, lower interest expense of $0.4 million on the 9 1/2% Notes which were redeemed and lower facility fees of $0.2 million were partially offset by a lower benefit on the interest rate swaps of $1.0 million which was due to the termination of the remaining swaps in the second quarter 2003.

Loss on Early Extinguishment of Debt. We redeemed $157.2 million of our 9 1/2% Notes due 2008 and the remaining $2.4 million of our 9 1/2% Notes due 2006 during the three months ended June 30, 2003. In connection with the redemptions, we paid a premium of $7.5 million and wrote off $ 3.4 million of deferred financing costs.

Dividends. Dividends on the TECONS were $1.7 million in both the three months ended June 30, 2003 and 2002. The TECONS pay dividends at a rate of 5.75%.

Income Tax. We had income tax expense of $4.2 million including current tax of $0.6 million for the three months ended June 30, 2003, compared to an expense of $9.9 million in the prior year period which had no current tax. The current tax relates to California State income tax which deferred the use of net operating losses for two years and Federal income tax. Our effective income tax rate was 38.9% in 2003 and 40.5% in 2002.

Discontinued Operations. We had income from discontinued operations of $0.8 million for the three months ended June 30, 2003 compared to income of $2.0 million in same period of 2002. In 2003, we sold our Brea-Olinda and Union Island properties located onshore California and made the decision to sell our Orcutt Hill property located onshore California. In 2002 the income from discontinued operations consists of after-tax operating income from our Eastern fields which were sold in 2002 and operating income from the Brea-Olinda, Union Island and Orcutt Hill properties.

YEAR TO DATE JUNE 30, 2003 COMPARED TO YEAR TO DATE JUNE 30, 2002

We had net income of $33.1 million, or $1.70 per diluted share and income from continuing operations of $19.3 million, or $0.99 per diluted share for the six months ended June 30, 2003 as compared to net income of $18.0 million, or $1.05 per diluted share and income from continuing operations of $15.0 million, or $0.87 per diluted share in the same period of 2002. Income from continuing operations is discussed below.

Revenues

Oil and Gas Revenues. Oil and gas revenues increased 30% to $192.4 million for the six months ended June 30, 2003 from $148.4 million in the same period of 2002 due to significantly higher realized crude oil and natural gas prices and higher natural gas production which was partially offset by higher hedging losses in 2003. Crude oil production averaged 42.1 MBbls/day for the six months ended June 30, 2003 compared to 42.0 MBbls/day in the same period of 2002. Higher production from the Pakenham field which was acquired in September 2002 and the acquisition of an additional interest in Point Pedernales were partially offset by lower production offshore California due to mechanical downtime. The realized oil price for the six months ended June 30, 2003 was $21.46 per Bbl, an increase of $3.74 per Bbl from the same period in 2002. We had hedging losses of $20.0 million in the six months ended June 30, 2003 compared to hedging gains of $2.5 million in same period of 2002. Natural gas production averaged 37.9 MMcf per day for the six months ended June 30, 2003, an increase of 9.6 MMcf per day from the same period of 2002. The Pakenham field which was acquired in September 2002 averaged 15.6 MMcf per day during the six months ended June 30, 2003 and was partially offset by production declines at Pitas Point and mechanical downtime and normal declines onshore California. The realized natural gas price for the six months ended June 30, 2003 was $4.19 per Mcf, including a $0.35 per Mcf hedging loss, compared to $2.67 per Mcf from the comparable period in 2002 which had no production hedged.

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Costs and Expenses

Costs and Expenses. LOE for the six months ended June 30, 2003 totaled $81.4 million, as compared to $67.0 million for the 2002 period. The increased LOE is due to higher steam costs in our onshore California operations, field costs from our Pakenham field which was acquired in 2002 and the acquisition of an additional interest in our Point Pedernales property. Exploration costs were $1.4 million in the six months ended June 30, 2003 compared to $1.5 million in the same period of 2002. Exploration costs in 2003 included the dry hole cost of Chott Fejaj in Tunisia while the 2002 costs were primarily seismic acquisitions. DD&A was $35.1 million for the six months ended June 30, 2003, compared to $34.7 million in the same period of 2002. The DD&A rate was $4.00 per BOE in the 2003 period compared to $4.10 per BOE in 2002. General and administrative expense of $13.1 million in 2003 was $0.2 million lower than the comparable period in 2002 due to lower outsourcing costs. The gain on disposition of properties was $4.5 million for the six months ended June 30, 2003 as compared to a $15.3 million gain in 2002. The 2003 gain was due to the release of escrow related to the sale of properties in 2001. In 2002, under the terms of a settlement agreement with ExxonMobil, we conveyed to them our interest in the Santa Ynez Unit, our non-consent interest in the adjacent Pescado field and relinquished our right to participate in the Sacate field and recorded a $14.7 million gain related to the sale of this unproved property.

Derivative Gain (Loss). Our derivative loss for the six months ended June 30, 2003 was $1.7 million compared to a loss of $0.9 million in the same period of 2002. The derivative loss is comprised of a loss on our mark-to-market derivatives and ineffectiveness of our hedges.

Interest Expense. Interest expense was $18.4 million for the six months ended June 30, 2003 compared to interest expense of $18.2 million in the same period of 2002. Lower interest expense on our line of credit of $0.8 million, lower interest expense of $0.4 million on the 9 1/2% Notes which were redeemed and lower facility fees of $0.4 million were more than offset by a lower benefit on the interest rate swaps of $1.9 million which was due to fewer swaps and a lower benefit on interest rate swaps which were terminated in the second quarter 2003.

Loss on Early Extinguishment of Debt. In 2003 we redeemed $157.2 million of our 9 1/2% Notes due 2008 and $2.4 million of our 9 1/2% Notes due 2006. In connection with the redemptions, we paid a premium of $7.5 million and wrote off $3.4 million of deferred financing costs.

Dividends. Dividends on the TECONS were $3.3 million in both the six months ended June 30, 2003 and 2002. The TECONS pay dividends at a rate of 5.75%.

Income Tax. We had income tax expense of $12.7 million including current tax of $2.1 million for the six months ended June 30, 2003, compared to an expense of $10.2 million in the prior year period which had no current tax. The current tax relates to California State income tax which deferred the use of net operating losses for two years and Federal income tax. Our effective income tax rate was 39.6% in 2003 and 40.5% in 2002.

Discontinued Operations. We had income from discontinued operations of $5.3 million for the six months ended June 30, 2003 compared to income of $3.1 million in same period of 2002. In 2003, we sold our Brea-Olinda and Union Island properties located onshore California and made the decision to sell our Orcutt Hill property located onshore California. We recognized a $7.7 million gain on the sale of the Union Island property and a $5.4 million loss in connection with writing down the Orcutt Hill property to the estimated fair value less our costs to sell the property. In 2002 the income from discontinued operations consists of after-tax operating income from our Eastern fields which were sold in 2002 and operating income from the Brea-Olinda, Union Island and Orcutt Hill properties.

Cumulative Effect of Change in Accounting Principle. In January 2003, we adopted SFAS No. 143. In connection with the initial application, we recorded a cumulative effect of change in accounting principle, net of taxes, of $8.5 million as an increase to income (See Note 1 to the Condensed Consolidated Financial Statements).

CAPITAL RESOURCES AND LIQUIDITY

Major sources of cash in the first half of 2003 were net cash provided by operating activities of $85.1 million, proceeds from the sale of properties of $69.9 million, borrowings under the bank credit agreement of $37.5 million, and $1.8 million of other investing activities. We used this cash, along with cash on hand at the beginning of the year, to fund capital expenditures on our oil and gas and other properties of $32.6 million and to redeem $159.6 million of our outstanding senior subordinated notes, plus a $7.5 million call premium. The redemption of the notes will result in lower cash interest expense on our 9 1/2% notes of $15.1 million per year.

Current assets decreased from $157.6 million at December 31, 2002 to $118.8 million at June 30, 2003 principally due to the sale of our Brea-Olinda property which was sold in the first quarter and removed from assets held for sale. Accounts receivable rose $7.7 million due to a crude oil lifting in Congo that occurred in June 2003.

We believe our working capital, cash flow from operations and available financing sources are sufficient to meet our obligations as they become due and to finance our capital budget through 2003. We have a $200.0 million borrowing base under our Credit Agreement. Under the most restrictive covenant, $131.6 million was available at June 30, 2003 and we had $66.2 million outstanding. We have letters of credit outstanding of $2.2 million under our Credit Agreement.

CONTINGENCIES AND OTHER MATTERS

See Item 1, Financial Statements, Note 9, which is incorporated herein by reference.

NEW ACCOUNTING PRONOUNCEMENTS

See Item 1, Financial Statements, Note 1, which is incorporated herein by reference.

CAUTIONARY STATEMENT FOR PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This report contains or incorporates by reference forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, Section 21E of the Securities Exchange Act of 1934 and the Private Securities Litigation Reform Act of 1995. All statements other than statements of historical facts included in this document, including without limitation, statements in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations regarding our financial position, estimated quantities and net present values of reserves, business strategy, plans and objectives of our management for future operations and covenant compliance, are forward looking statements. We can give no assurances that the assumptions upon which such forward-looking statements are based will prove to be correct. Important factors that could cause actual results to differ materially from our expectations are included throughout this document. The cautionary statements expressly qualify all subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information contained in this item updates, and should be read in conjunction with Part II, Item 7A of our Annual Report on Form 10-K for the year ended December 31, 2002.

At June 30, 2003, we had entered into the following cash flow hedges:

	Crude Oil			Natur	
	Bbls / day	$ / Bbl	Index	MMbtu/day	$
Swaps for Sales					
2003					
3rd Qtr............	13,500	$ 23.62	WTI	7,500	$
4th Qtr............	13,500	23.79	WTI	8,000	
2004					
1st Qtr............	14,500	23.76	WTI	16,500	
2nd Qtr............	13,500	24.03	WTI	14,500	
3rd Qtr............	11,000	23.64	WTI	10,500	
4th Qtr............	6,500	23.23	WTI	14,500	
2005					
Full Year..........	4,500	22.14	WTI		
Collars					
2003					
Full Year..........	10,000	22.00-28.91	WTI		
3rd Qtr............				6,000	

4th Qtr...........	6,000
Swaps for Purchases	
2004..............	8,000
2005..............	8,000

Subsequent to June 30, 2003, we entered into the following cash flow hedges:

	Crude Oil			N
	Bbls / day	$ / Bbl	Index	MMbtu/day
Swaps for Sales				
2004				
4th Qtr.............	2,000	25.50	WTI	
2005				
1st Qtr.............	5,000	25.20	WTI	3,500

ITEM 4. CONTROLS AND PROCEDURES

The term "disclosure controls and procedures" is defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, or the Exchange Act. This term refers to the controls and procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the Securities and Exchange Commission. Our management, including our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures as of the end of the period covered by this quarterly report. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures were effective as of the end of the period covered by this quarterly report.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

See Part I, Item 1, Financial Statements, Note 9, which is incorporated herein by reference.

ITEM 2. CHANGES IN SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

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

We held our Annual Meeting of Stockholders on May 21, 2003. Proposals presented for a stockholders' vote included the election of eight directors, the ratification of KPMG LLP as independent auditors for 2003 and the ratification of certain stock incentive plans.

Election of Board of Directors

Each of the eight directors was elected with the following results:

	For	Withheld
Isaac Arnold, Jr..........	17,145,843	343,659
Charles M. Elson..........	17,145,843	343,659
Robert L. Gerry III.......	13,949,949	3,539,553
J. Frank Haasbeek.........	17,146,697	342,805
James T. Jongebloed.......	16,381,793	1,107,709
James L. Payne............	17,147,093	342,409
Gary R. Petersen..........	17,147,093	342,409
Sheryl K. Pressler........	17,147,253	342,409

Ratification of Appointment of Independent Auditors

The appointment of KPMG LLP as our independent auditors for 2003 was ratified with the following results:

	For	Against	Abstain
KPMG LLP..................	16,668,000	808,407	13,095

Ratification of Certain Stock Incentive Plans

Certain stock incentive plans approved by the board of directors were ratified and approved with the following results:

	For	Against	Abstain
Stock Incentive Plan......	12,552,907	4,458,887	507,708

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K

(a) EXHIBITS:

31.1	Certification of Chief Executive Officer of Nuevo Energy Company pursuant to S the Sarbanes-Oxley Act of 2002
31.2	Certification of Chief Financial Officer of Nuevo Energy Company pursuant to S the Sarbanes-Oxley Act of 2002
32.1	Certification of Chief Executive Officer of Nuevo Energy Company pursuant to S the Sarbanes-Oxley Act of 2002
32.2	Certification of Chief Financial Officer of Nuevo Energy Company pursuant to S the Sarbanes-Oxley Act of 2002

(b) REPORTS ON FORM 8-K:

DATE	EVENT REPORTED
May 14, 2003	Press release announcing first quarter 2003 earnings
May 28, 2003	Press release announcing the partial redemption of the 9 1/2% Subordinated Notes
June 24, 2003	Press release announcing the completion of the partial redempt 9 1/2% Senior Subordinated Notes
August 12, 2003	Press release announcing second quarter 2003 earnings

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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.

NUEVO ENERGY COMPANY
(Registrant)

Date: August 13, 2003 By: /s/ James L. Payne

	James L. Payne Chairman, President and Chief Executive Officer
Date: August 13, 2003	By: /s/ Janet F. Clark
	Janet F. Clark Senior Vice President and Chief Financial Officer

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EXHIBIT INDEX

EXHIBIT NUMBER	DESCRIPTION
31.1	Certification of Chief Executive Officer of Nuevo Energy Company pursuant to Sect the Sarbanes-Oxley Act of 2002
31.2	Certification of Chief Financial Officer of Nuevo Energy Company pursuant to Sect the Sarbanes-Oxley Act of 2002
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