NOBLE ENERGY INC
Form 10-Q
October 31, 2007

UNITED STATES
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, 2007

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: 001-07964

NOBLE ENERGY, INC.

(Exact name of registrant as specified in its charter)

Delaware	**73-0785597**
(State of incorporation)	(I.R.S. employer identification number)

100 Glenborough Drive, Suite 100	
Houston, Texas	**77067**
(Address of principal executive offices)	(Zip Code)

(281) 872-3100

(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 o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated

filer. See definition of “accelerated filer and large accelerated filer” in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer x Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No x

Number of shares of common stock outstanding as of October 24, 2007: 171,449,686

PART I. FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS

Noble Energy, Inc. and Subsidiaries
Consolidated Balance Sheets
(in thousands, except share amounts)

	(Unaudited) September 30, 2007	December 31, 2006
ASSETS		
Current Assets		
Cash and cash equivalents	$ 450,773	$ 153,408
Accounts receivable - trade, net	555,850	586,882
Deferred income taxes	64,337	99,835
Probable insurance claims	12,193	101,233
Other current assets	114,857	127,188
Total current assets	1,198,010	1,068,546
Property, plant and equipment		
Oil and gas properties (successful efforts method of accounting)	9,924,532	8,867,639
Other property, plant and equipment	93,475	79,646
	10,018,007	8,947,285
Accumulated depreciation, depletion and amortization	(2,292,108)	(1,776,528)
Total property, plant and equipment, net	7,725,899	7,170,757
Other noncurrent assets	561,270	568,032
Goodwill	766,249	781,290
Total Assets	$ 10,251,428	$ 9,588,625
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable - trade	$ 588,453	$ 518,609
Derivative instruments	372,027	254,625
Income taxes	54,055	107,136
Short-term borrowings	25,000	-
Asset retirement obligations	15,081	68,500
Other current liabilities	176,579	235,392
Total current liabilities	1,231,195	1,184,262
Deferred income taxes	1,882,518	1,758,452
Asset retirement obligations	108,589	127,689
Derivative instruments	127,944	328,875
Other noncurrent liabilities	341,873	274,720
Long-term debt	1,941,018	1,800,810
Total Liabilities	5,633,137	5,474,808
Commitments and Contingencies		
Shareholders' Equity		
Preferred stock - par value $1.00; 4,000,000 shares authorized, none issued	-	-
Common stock - par value $3.33 1/3; 250,000,000 shares authorized; 190,462,250 and 188,808,087 shares issued, respectively	634,860	629,360
Capital in excess of par value	2,088,891	2,041,048

Accumulated other comprehensive loss		(177,023)		(140,509)
Treasury stock, at cost:18,580,865 and 16,574,384 shares, respectively		(612,976)		(511,443)
Retained earnings		2,684,539		2,095,361
Total Shareholders' Equity		4,618,291		4,113,817
Total Liabilities and Shareholders' Equity	$	10,251,428	$	9,588,625

The accompanying notes are an integral part of these financial statements

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Noble Energy, Inc. and Subsidiaries
Consolidated Statements of Operations
(in thousands, except per share amounts)
(Unaudited)

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Revenues				
Oil and gas sales	$ 746,258	$ 683,544	$ 2,140,218	$ 2,044,656
Income from equity method investees	45,371	33,810	139,904	108,901
Other revenues	22,182	23,965	70,447	72,339
Total Revenues	813,811	741,319	2,350,569	2,225,896
Costs and Expenses				
Lease operating costs	81,767	76,928	243,205	238,307
Production and ad valorem taxes	26,752	30,697	80,667	83,663
Transportation costs	13,260	4,531	40,346	18,463
Exploration costs	45,794	30,904	144,796	92,327
Depreciation, depletion and amortization	195,266	165,765	540,453	458,878
General and administrative	49,518	40,657	142,368	113,716
Accretion of discount on asset retirement obligations	1,909	2,426	6,337	8,405
Interest, net of amount capitalized	29,247	28,556	87,105	95,642
Loss (gain) on derivative instruments	1,514	(6,315)	(557)	389,723
Loss (gain) on sale of assets	1,684	(200,676)	(4,381)	(211,691)
Loss on involuntary conversion	-	-	51,406	-
Other expense, net	23,823	22,880	78,594	89,008
Total Costs and Expenses	470,534	196,353	1,410,339	1,376,441
Income Before Taxes	343,277	544,966	940,230	849,455
Income Tax Provision	120,602	226,902	296,638	336,009
Net Income	$ 222,675	$ 318,064	$ 643,592	$ 513,446
Earnings Per Share				
Basic	$ 1.30	$ 1.80	$ 3.76	$ 2.91
Diluted	$ 1.28	$ 1.75	$ 3.72	$ 2.85
Weighted average number of shares outstanding				
Basic	171,123	176,218	170,953	176,505
Diluted	173,350	181,077	173,156	180,158

The accompanying notes are an integral part of these financial statements

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Noble Energy, Inc. and Subsidiaries
Consolidated Statements of Cash Flows
(in thousands)
(Unaudited)

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Cash Flows From Operating Activities		
Net income	$ 643,592	$ 513,446
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization - oil and gas production	540,453	458,878
Depreciation, depletion and amortization - electricity generation	10,558	11,842
Dry hole expense	47,769	24,164
Impairment of operating assets	3,661	6,359
Amortization of unproved leasehold costs	12,700	15,180
Stock-based compensation expense	20,040	9,320
Gain on sale of assets	(4,381)	(211,691)
Deferred income taxes	192,137	146,709
Accretion of discount on asset retirement obligations	6,337	8,405
Increase in allowance for doubtful accounts	10,780	10,564
Income from equity method investees	(139,904)	(108,901)
Dividends from equity method investees	153,331	18,000
Deferred compensation expense	23,089	15,673
(Gain) loss on derivative instruments	(133,580)	430,328
Loss on involuntary conversion	51,406	-
Other	6,861	(17,657)
Changes in operating assets and liabilities, net of acquisition:		
Decrease (increase) in accounts receivable - trade	20,984	(41,222)
(Increase) decrease in other current assets	(2,733)	13,479
Decrease in probable insurance claims	94,695	101,612
Decrease in accounts payable	(11,875)	(29,246)
Decrease in other current liabilities	(225,309)	(34,429)
Net Cash Provided by Operating Activities	1,320,611	1,340,813
Cash Flows From Investing Activities		
Additions to property, plant and equipment	(1,017,702)	(1,030,430)
U.S. Exploration acquisition, net of cash acquired	-	(412,257)
Proceeds from sales of assets	-	504,259
Investments in equity method investees	-	(5,126)
Distributions from equity method investees	2,100	116,521
Net Cash Used in Investing Activities	(1,015,602)	(827,033)
Cash Flows From Financing Activities		
Exercise of stock options	19,381	50,576
Tax benefits from stock-based awards	13,922	18,534
Cash dividends paid	(54,414)	(35,776)
Purchases of treasury stock	(101,533)	(192,632)
Proceeds from credit facility	280,000	300,000
Repayment of credit facility	(165,000)	(605,000)
Repayment of term loans	-	(105,000)
Net proceeds from short term borrowings	-	35,000

Net Cash Used in Financing Activities	(7,644)	(534,298)
Increase (Decrease) in Cash and Cash Equivalents	297,365	(20,518)
Cash and Cash Equivalents at Beginning of Period	153,408	110,321
Cash and Cash Equivalents at End of Period	$ 450,773	$ 89,803

The accompanying notes are an integral part of these financial statements

Noble Energy, Inc. and Subsidiaries
Consolidated Statements of Shareholders' Equity
(in thousands)
(Unaudited)

	Common Stock Shares	Common Stock Amount	Capital in Excess of Par Value	Deferred Compensation - Restricted Stock	Accumulated Other Comprehensive Loss	Treasury Stock at Cost	Retained Earnings	Total Shareholders' Equity
December 31, 2006	188,808	$ 629,360	$ 2,041,048	$ -	$ (140,509)	$ (511,443)	$ 2,095,361	$ 4,113,817
Net income	-	-	-	-	-	-	643,592	643,592
Stock-based compensation expense	-	-	20,040	-	-	-	-	20,040
Exercise of stock options	1,128	3,760	15,621	-	-	-	-	19,381
Tax benefits from stock-based awards	-	-	13,922	-	-	-	-	13,922
Restricted stock grants, net	526	1,740	(1,740)	-	-	-	-	-
Dividends ($0.315 per share)	-	-	-	-	-	-	(54,414)	(54,414)
Purchases of treasury stock	-	-	-	-	-	(101,533)	-	(101,533)
Oil and gas cash flow hedges:								
Realized amounts reclassified into earnings	-	-	-	-	5,180	-	-	5,180
Unrealized change in fair value	-	-	-	-	(44,006)	-	-	(44,006)
Net change in other	-	-	-	-	2,312	-	-	2,312
September 30, 2007	190,462	$ 634,860	$ 2,088,891	$ -	$ (177,023)	$ (612,976)	$ 2,684,539	$ 4,618,291
December 31, 2005	184,894	$ 616,311	$ 1,945,239	$ (5,288)	$ (783,499)	$ (148,476)	$ 1,465,857	$ 3,090,144
Net income	-	-	-	-	-	-	513,446	513,446
Adoption of SFAS 123(R), net of tax	-	-	(5,288)	5,288	-	-	-	-
Stock-based compensation expense	-	-	9,320	-	-	-	-	9,320
	2,815	9,382	41,194	-	-	-	-	50,576

Exercise of stock options								
Tax benefits from stock-based awards	-	-	18,534	-	-	-	-	18,534
Restricted stock grants, net	64	217	(217)	-	-	-	-	-
Dividends ($0.20 per share)	-	-	-	-	-	-	(35,776)	(35,776)
Rabbi trust shares sold	-	-	7,837	-	-	24,005	-	31,842
Purchases of treasury stock	-	-	-	-	-	(192,632)	-	(192,632)
Oil and gas cash flow hedges:								
Realized amounts reclassifed into earnings	-	-	-	-	136,546	-	-	136,546
Unrealized change in fair value	-	-	-	-	197,239	-	-	197,239
Unrealized amounts reclassified into earnings	-	-	-	-	264,265	-	-	264,265
Net change in other	-	-	-	-	533	-	-	533
September 30, 2006	187,773	$ 625,910	$ 2,016,619	$ -	$ (184,916)	$ (317,103)	$ 1,943,527	$ 4,084,037

The accompanying notes are an integral part of these financial statements

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Noble Energy, Inc. and Subsidiaries
Consolidated Statements of Comprehensive Income
(in thousands)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Net income	$ 222,675	$ 318,064	$ 643,592	$ 513,446
Other items of comprehensive income (loss)				
Oil and gas cash flow hedges:				
Realized amounts reclassified into earnings	12,324	43,798	8,302	219,035
Less tax provision	(4,634)	(16,494)	(3,122)	(82,489)
Unrealized change in fair value	11,804	274,361	(70,523)	266,483
Less tax provision	(4,438)	(87,952)	26,517	(69,244)
Unrealized amounts reclassified into earnings	-	-	-	423,910
Less tax provision	-	-	-	(159,645)
Net change in other:	186	354	3,705	855
Less tax provision	(70)	(134)	(1,393)	(322)
Other comprehensive income (loss)	15,172	213,933	(36,514)	598,583
Comprehensive income	$ 237,847	$ 531,997	$ 607,078	$ 1,112,029

The accompanying notes are an integral part of these financial statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

Note 1 - Organization and Nature of Operations

Noble Energy, Inc. ("Noble Energy", "we", "our" or "us") is an independent energy company engaged in the exploration, development, production and marketing of crude oil and natural gas. We have exploration, exploitation and production operations domestically and internationally. We operate throughout major basins in the US including Colorado's Wattenberg field, the Mid-continent area of western Oklahoma and the Texas Panhandle, the San Juan Basin in New Mexico, the Gulf Coast and the deepwater Gulf of Mexico. In addition, we conduct business internationally in West Africa (Equatorial Guinea and Cameroon), the Mediterranean Sea (Israel), Ecuador, the North Sea (UK, the Netherlands and Norway), China, Argentina and Suriname.

Note 2 - Basis of Presentation

Presentation – The accompanying unaudited consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the US for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and notes required by US generally accepted accounting principles ("GAAP") for complete financial statements. The accompanying unaudited consolidated financial statements at September 30, 2007 and December 31, 2006 and for the three and nine months ended September 30, 2007 and 2006 contain all normally recurring adjustments considered necessary for a fair presentation of our financial position, results of operations and cash flows for such periods. Operating results for the three and nine months ended September 30, 2007 are not necessarily indicative of the results that may be expected for the year ending December 31, 2007. Certain reclassifications of amounts previously reported have been made to conform to current year presentations. These consolidated financial statements should be read in conjunction with the consolidated financial statements and the notes included in our annual report on Form 10-K for the year ended December 31, 2006.

Estimates – The preparation of consolidated financial statements in conformity with GAAP requires us to make a number of estimates and assumptions relating to the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ significantly from those estimates.

Balance Sheet and Statement of Operations Information –
Other balance sheet and statement of operations information is as follows:

	September 30, 2007	December 31, 2006
	(in thousands)	
Other Current Assets		
Derivative instruments	$ 20,282	$ 35,242
Materials and supplies inventories	62,399	46,973
Prepaid expenses and other current assets	32,176	44,973
Total	$ 114,857	$ 127,188
Other Noncurrent Assets		
Equity method investments	$ 358,940	$ 373,372
Mutual fund investments	125,860	116,314
Probable insurance claims	40,846	46,500
Derivative instruments	5,172	2,862
Other noncurrent assets	30,452	28,984
Total	$ 561,270	$ 568,032
Other Current Liabilities		
Accrued and other current liabilities	$ 151,292	$ 219,885
Interest payable	25,287	15,507
Total	$ 176,579	$ 235,392
Other Noncurrent Liabilities		
Deferred compensation liability	$ 207,825	$ 173,253
Accrued benefit costs	57,850	58,491
Other noncurrent liabilities	76,198	42,976
Total	$ 341,873	$ 274,720

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(in thousands)			
Other Revenues				
Electricity sales	$ 16,616	$ 16,241	$ 53,745	$ 49,672
Gathering, marketing and processing	5,566	7,724	16,702	22,667
Total	$ 22,182	$ 23,965	$ 70,447	$ 72,339
Other Expense, net				
Electricity generation	$ 13,679	$ 17,876	$ 41,941	$ 43,099
Gathering, marketing and processing	4,100	4,204	13,093	15,674
Deferred compensation expense	8,423	933	23,089	15,673
Impairment of operating assets	3,661	-	3,661	6,359
Other	(6,040)	(133)	(3,190)	8,203
Total	$ 23,823	$ 22,880	$ 78,594	$ 89,008

Note 3 - Derivative Instruments and Hedging Activities

Cash Flow Hedges – We use various derivative instruments in connection with forecasted crude oil and natural gas sales to mitigate the variability of cash flows associated with commodity price fluctuations. Such instruments include variable to fixed price swaps, costless collars and basis swaps. While these instruments mitigate the cash flow risk of future reductions in commodity prices they may also curtail benefits from future increases in commodity prices.

We account for derivative instruments and hedging activities in accordance with Statement of Financial Accounting Standards (“SFAS”) No. 133, “Accounting for Derivative Instruments and Hedging Activities,” as amended, and have elected to designate certain of our derivative instruments as cash flow hedges. Derivative instruments designated as cash flow hedges are reflected at fair value in the consolidated balance sheets. Changes in fair value, to the extent the hedge is effective, are reported in accumulated other comprehensive income or loss (“AOCL”) until the forecasted transaction occurs. Gains and losses from such derivative instruments related to our crude oil and natural gas sales, and which qualify for hedge accounting treatment, are recorded in oil and gas sales on our consolidated statements of operations upon sale of the associated commodity. We assess hedge effectiveness quarterly based on total changes in the derivative’s fair value. Any ineffective portion of the derivative instrument’s change in fair value is immediately recognized in earnings.

(Gain) loss on derivative instruments included the following:

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(in thousands)			
Ineffectiveness (gains) losses	$ 1,514	$ (2,957)	$ (557)	$ 8,384
Reclassified from AOCL	-	-	-	423,910
Mark-to-market gain on derivative instruments not accounted for as cash flow hedges	-	(3,358)	-	(42,571)
Loss (gain) on derivative instruments	$ 1,514	$ (6,315)	$ (557)	$ 389,723

During 2006, $424 million of losses deferred in AOCL were reclassified to our earnings when it became probable that forecasted sales would not occur. Of this amount, $399 million related to the sale of Gulf of Mexico shelf assets.

Effects of cash flow hedges on natural gas and crude oil sales were as follows:

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(in thousands)			
Increase (decrease) in natural gas sales	$ 47,973	$ 2,588	$ 120,057	$ (59,348)
Decrease in crude oil sales	(60,297)	(46,386)	(128,359)	(159,687)
Total decrease in oil and gas sales	$ (12,324)	$ (43,798)	$ (8,302)	$ (219,035)

The increase in natural gas sales in 2007 includes non-cash increases related to hedge contracts that were re-designated at the time of our Gulf of Mexico shelf asset sale in 2006 and settled during the first nine months of 2007. These non-cash increases totaled $42 million for third quarter 2007 and $133 million for the first nine months of 2007.

At September 30, 2007, we had entered into, and designated as cash flow hedges, the following variable to fixed price swap derivative instruments related to natural gas and crude oil sales.

Production Period	Natural Gas MMBtupd	Natural Gas Average Price per MMBtu	Crude Oil Bopd	Crude Oil Average price per Bbl
October - December 2007 (NYMEX)	170,000	$ 5.97	17,100	$ 38.74
2008 (NYMEX)	170,000	5.66	16,500	38.23

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At September 30, 2007, we had entered into basis swap derivative instruments related to natural gas sales. These basis swaps have been combined with NYMEX variable to fixed swaps and designated as cash flow hedges. The basis swaps are as follows:

	Natural Gas	
Production Period	MMBtupd	Average Differential per MMBtu
October - December 2007 (CIG [1] vs. NYMEX)	100,000	$ 2.02
October - December 2007 (ANR [2] vs. NYMEX)	30,000	1.17
October - December 2007 (PEPL [3] vs. NYMEX)	10,000	1.11
2008 (CIG vs. NYMEX)	100,000	1.66
2008 (ANR vs. NYMEX)	40,000	1.01
2008 (PEPL vs. NYMEX)	10,000	0.98

[1] Colorado Interstate Gas - Northern System
[2] ANR Oklahoma Pipeline
[3] Panhandle Eastern Pipe Line

At September 30, 2007, we had entered into, and designated as cash flow hedges, the following costless collar derivative instruments related to natural gas and crude oil sales.

	Natural Gas			Crude Oil		
		Average price per MMBtu			Average price per Bbl	
Production Period	MMBtupd	Floor	Ceiling	Bopd	Floor	Ceiling
October - December 2007 (NYMEX)	-	$ -	$ -	2,700	$ 60.00	$ 74.30
October - December 2007 (CIG)	12,000	6.50	9.50	-	-	-
October - December 2007 (Dated Brent)	-	-	-	5,565	45.00	70.29
2008 (NYMEX)	-	-	-	3,100	60.00	72.40
2008 (CIG)	14,000	6.75	8.70	-	-	-
2008 (Dated Brent)	-	-	-	4,074	45.00	66.52
2009 (NYMEX)	-	-	-	3,700	60.00	70.00
2009 (CIG)	15,000	6.00	9.90	-	-	-
2009 (Dated Brent)	-	-	-	3,074	45.00	63.04
2010 (NYMEX)	-	-	-	3,500	55.00	73.80
2010 (CIG)	15,000	6.25	8.10	-	-	-

If commodity prices were to stay the same as they were at September 30, 2007, approximately $107 million of deferred losses, net of taxes, related to the fair values of the derivative instruments included in AOCL at September 30, 2007 would be reversed during the next twelve months as the forecasted transactions occur, and settlements would be recorded as a reduction in oil and gas sales. All forecasted transactions currently being hedged are expected to occur through December 2010.

Note 4 – Defined Benefit Pension, Restoration and Medical and Life Plans

We have a noncontributory, tax-qualified defined benefit pension plan covering certain domestic employees. We also have an unfunded, nonqualified restoration plan that provides the pension plan formula benefits that cannot be provided by the qualified pension plan because of pay deferrals and the compensation and benefit limitations imposed on the pension plan by the Internal Revenue Code of 1986, as amended. We sponsor other plans for the benefit of our employees and retirees, which include medical and life insurance benefits. Net periodic benefit cost related to the pension, restoration and medical and life plans was as follows:

	Retirement & Restoration Plan Benefits		Medical & Life Plan Benefits	
	2007	2006	2007	2006
	(in thousands)			
Three Months Ended September 30,				
Service cost	$ 2,579	$ 2,400	$ 468	$ 420
Interest cost	2,536	2,224	307	296
Expected return on plan assets	(2,898)	(2,046)	-	-
Transition obligation recognition	60	60	-	-
Amortization of prior service cost	(129)	(114)	(231)	(246)
Recognized net actuarial loss	560	420	204	320
Net periodic benefit cost	$ 2,708	$ 2,944	$ 748	$ 790
Nine Months Ended September 30,				
Service cost	$ 8,753	$ 8,406	$ 1,472	$ 1,692
Interest cost	7,484	6,736	893	986
Expected return on plan assets	(8,284)	(6,027)	-	-
Transition obligation recognition	180	180	-	-
Amortization of prior service cost	(387)	(66)	(695)	(489)
Recognized net actuarial loss	2,516	1,660	790	868
Net periodic benefit cost	$ 10,262	$ 10,889	$ 2,460	$ 3,057

Cash contributions to the pension plan totaled $10 million during third quarter 2007.

Note 5 - Stock-Based Compensation

We recognized stock-based compensation expense as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(in thousands)			
Stock-based compensation expense	$ 7,962	$ 2,997	$ 20,040	$ 9,320
Tax benefit from expense recognized	2,994	1,129	7,535	3,510

During the nine months ended September 30, 2007, we granted 1,535,919 stock options with a weighted-average grant-date fair value of $18.72 per option and awarded 538,893 shares of restricted stock with a weighted-average grant-date fair value of $53.63 per share.

Note 6 - Effect of Gulf Coast Hurricanes

We have completed our cleanup activities relating to the damage caused by Hurricane Ivan in 2004 and Katrina in 2005. During early third quarter 2007, we completed the lifting and removal of the four platform decks that were sheared from their supporting structures during the storms.

During the first half of 2007, several factors contributed to an increase in our estimated cleanup costs for damage related to Hurricanes Ivan and Katrina. These factors included cost escalation due to weather delays and an increase in effort for the design and construction of the deck lifting barge and mooring system, as well as additional costs for the actual deck lifting activities. These increases caused the total project costs, combined with net book value of the assets destroyed, to exceed certain insurance coverage limitations. As a result, we recorded $51 million as a loss on involuntary conversion for the first six months of 2007.

As of September 30, 2007, we have recorded probable insurance claims of $53 million. We are currently assessing the scope and timing of our redevelopment of the Main Pass properties. Ultimate recovery of our insurance claim is associated with redevelopment or possible settlement resolution with our insurance providers.

Insurance reimbursements received to date have been for cleanup and repair costs and are included in cash flows from operating activities.

Note 7 - Asset Retirement Obligations

Asset retirement obligations consist primarily of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. Changes in asset retirement obligations were as follows:

		Nine Months Ended September 30, 2007 (in thousands)
Asset retirement obligations at December 31, 2006	$	196,189
Liabilities incurred in current period		5,926
Liabilities settled in current period		(163,226)
Revisions		78,444
Accretion expense		6,337
Asset retirement obligations at September 30, 2007	$	123,670

Liabilities settled and revisions during the period were primarily related to cleanup of hurricane damage at Main Pass.

Note 8 – Equity Method Investments

Equity method investments are included in other noncurrent assets in the consolidated balance sheets, and our share of earnings is reported as income from equity method investees in our consolidated statements of operations. Our share of income taxes incurred directly by the equity method investees is reported in income from equity method investees and is not included in our income tax provision in our consolidated statements of operations.

Equity method investments are as follows:

	September 30, 2007	December 31, 2006
	(in thousands)	
Equity method investments:		
Atlantic Methanol Production Company, LLC ("AMPCO") (45% interest)	$ 204,091	$ 211,325
Alba Plant LLC ("Alba Plant") (27.8% interest)	140,501	146,051
Other	14,348	15,996
Total equity method investments	$ 358,940	$ 373,372

Summarized, 100%, combined financial information for AMPCO, Alba Plant and other equity method investees is as follows:

	September 30, 2007	December 31, 2006
	(in thousands)	
Balance sheet information:		
Current assets	$ 262,330	$ 252,201
Noncurrent assets	839,524	857,465
Current liabilities	165,987	171,028
Noncurrent liabilities	2,181	2,385

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(in thousands)			
Statements of operations information:				
Operating revenues	$ 218,584	$ 179,087	$ 641,897	$ 533,949
Less cost of goods sold	57,309	55,157	161,606	145,900
Gross margin	161,275	123,930	480,291	388,049
Less other expense, net	8,488	9,993	28,977	36,654
Less income tax expense	8,966	1,956	27,598	18,795
Net income	$ 143,821	$ 111,981	$ 423,716	$ 332,600

Note 9 - Basic and Diluted Earnings Per Share

Basic earnings per share ("EPS") of common stock were computed using the weighted average number of shares of common stock outstanding during each period. The diluted earnings per share of common stock include the effect of outstanding stock options and restricted stock. The following table summarizes the calculation of basic and diluted EPS:

	2007		2006	
	Net Income	Weighted Average Shares	Net Income	Weighted Average Shares
	(in thousands, except per share amounts)			
Three Months Ended September 30,				
Net income available to common shareholders and weighted average shares outstanding	$ 222,675	171,123	$ 318,064	176,218
Basic EPS	$ 1.30		$ 1.80	
Net income available to common shareholders and weighted average shares outstanding	$ 222,675	171,123	$ 318,064	176,218
Plus incremental shares from assumed conversions:				
Dilutive stock options	-	1,983	-	3,198
Dilutive restricted stock	-	244	-	141
Dilutive rabbi trust shares	-	-	$ (708)	1,520
Adjusted net income and shares	$ 222,675	173,350	$ 317,356	181,077
Diluted EPS	$ 1.28		$ 1.75	
Nine Months Ended September 30,				
Net income available to common shareholders and weighted average shares outstanding	$ 643,592	170,953	$ 513,446	176,505
Basic EPS	$ 3.76		$ 2.91	
Net income available to common shareholders and weighted average shares outstanding	$ 643,592	170,953	$ 513,446	176,505
Plus incremental shares from assumed conversions:				
Dilutive stock options	-	2,008	-	3,508
Dilutive restricted stock	-	195	-	145
Adjusted net income and shares	$ 643,592	173,156	$ 513,446	180,158
Diluted EPS	$ 3.72		$ 2.85	

Certain stock options, shares of restricted stock and shares of our common stock held in a rabbi trust were antidilutive and were excluded from the calculation of diluted EPS. These items represented 2.1 million and 0.8 million weighted average shares for third quarter 2007 and 2006, respectively, and 2.4 million and 2.0 million weighted average shares for the first nine months of 2007 and 2006, respectively.

Note 10 - Income Taxes

The income tax provision consists of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(in thousands)			

Current	$ 31,981	$ 127,252	$ 104,501	$ 189,300
Deferred	88,621	99,650	192,137	146,709
Total income tax provision	$ 120,602	$ 226,902	$ 296,638	$ 336,009

Our effective tax rate decreased from 39.6% for the first nine months of 2006 to 31.5% for the first nine months of 2007. Tax expense was higher in 2006 because $100 million of goodwill associated with the sale of our Gulf of Mexico shelf assets was not deductible, there was an increase in the valuation allowance on a deferred tax asset for future foreign tax credits and there was an increase in deferred tax liabilities due to a rate change in the UK. In addition, income from equity method investments was higher in 2007, which is a favorable permanent difference in calculating income tax expense.

In assessing whether or not deferred tax assets are realizable, we consider whether it is more likely than not that some portion of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. At December 31, 2006, we had recorded deferred tax assets subject to valuation allowances of $74 million related to foreign tax credits and losses on foreign operations. The valuation allowances with respect to the deferred tax assets totaled $74 million at December 31, 2006.

Adoption of FIN 48 and FSP FIN 48-1– We adopted FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109" ("FIN 48") as of January 1, 2007. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in a company's financial statements in accordance with Statement of Financial Accounting Standards ("SFAS") No. 109, "Accounting for Income Taxes". FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. We also adopted FASB Staff Position No. FIN 48-1, "Definition of Settlement in FASB Interpretation No. 48" ("FSP FIN 48-1") as of January 1, 2007. FSP FIN 48-1 provides that a company's tax position will be considered settled if the taxing authority has completed its examination, the company does not plan to appeal, and it is remote that the taxing authority would reexamine the tax position in the future. The adoption of FIN 48 and FSP FIN 48-1 had no effect on our financial position or results of operations.

As of adoption at January 1, 2007 and at September 30, 2007, we had unrecognized tax benefits totaling $400,000. These tax benefits are "unrecognized" because they did not meet the threshold for financial statement recognition, which provides that a tax position should be recognized if it is more likely than not, based on the technical merits, that the position will be sustained upon examination. If these tax benefits were to meet the recognition criteria in the future, they would be recognized in our financial statements and would affect our effective tax rate. In our major tax jurisdictions, the earliest years remaining open to examination are as follows: US - 2004, Equatorial Guinea - 2006, China - 2006, Israel - 2000, UK - 2005 and the Netherlands - 2005. We recognize interest and penalties related to unrecognized tax benefits in income tax expense. We had accrued no interest or penalties at September 30, 2007, because the jurisdiction in which we have unrecognized tax benefits does not currently impose interest on underpayments of tax, and we believe that we are below the minimum statutory threshold for imposition of penalties.

Note 11 - Segment Information

We have operations throughout the world and manage our operations by country. The following information is grouped into five components that are primarily in the business of natural gas and crude oil exploration and production: North America (US); West Africa (Equatorial Guinea and Cameroon); North Sea (UK, the Netherlands and Norway); Israel; and Other International, Corporate and Marketing. Other International includes Argentina, China, Ecuador and Suriname. The following data was prepared on the same basis as our consolidated financial statements. The information excludes the effects of income taxes except for equity method investees.

	Consolidated	North America	West Africa	North Sea	Israel	Other Int'l Corporate & Marketing
			(in thousands)			
Three Months Ended September 30, 2007						
Revenues from third parties	$ 768,440	$ 397,148	$ 97,893	$ 121,774	$ 35,626	$ 115,999
Intersegment revenue	-	60,201	-	-	-	(60,201)
Income from equity method investees	45,371	-	45,371	-	-	-
Total Revenues	813,811	457,349	143,264	121,774	35,626	55,798
Depreciation, depletion and amortization	195,266	143,574	8,716	29,741	5,178	8,057
Loss on derivative instruments	1,514	1,514	-	-	-	-
Income (loss) before taxes	343,277	181,291	112,273	77,536	27,957	(55,780)
Three Months Ended September 30, 2006						
Revenues from third parties	$ 707,509	$ 406,173	$ 85,498	$ 26,082	$ 30,451	$ 159,305
Intersegment revenue	-	99,549	-	-	-	(99,549)
Income from equity method investees	33,810	-	33,810	-	-	-
Total Revenues	741,319	505,722	119,308	26,082	30,451	59,756
Depreciation, depletion and amortization	165,765	146,010	5,353	2,603	4,115	7,684
Gain on derivative instruments	(6,315)	(6,315)	-	-	-	-
Income (loss) before taxes	544,966	435,432	107,206	15,707	24,785	(38,164)

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	Consolidated	North America	West Africa	North Sea	Israel	Other Int'l Corporate & Marketing
			(in thousands)			
Nine Months Ended September 30, 2007						
Revenues from third parties	$ 2,210,665	$ 1,209,760	$ 283,168	$ 239,104	$ 84,937	$ 393,696
Intersegment revenue	-	227,141	-	-	-	(227,141)
Income from equity method investees	139,904	-	139,904	-	-	-
Total Revenues	2,350,569	1,436,901	423,072	239,104	84,937	166,555
Depreciation, depletion and amortization	540,453	427,861	18,731	56,849	13,011	24,001
Gain on derivative instruments	(557)	(557)	-	-	-	-
Loss on involuntary conversion	51,406	51,406	-	-	-	-
Income (loss) before taxes	940,230	558,784	338,082	137,057	65,132	(158,825)
Nine Months Ended September 30, 2006						
Revenues from third parties	$ 2,116,995	$ 1,097,212	$ 306,870	$ 88,723	$ 68,441	$ 555,749
Intersegment revenue	-	372,656	-	-	-	(372,656)
Income from equity method investees	108,901	-	108,901	-	-	-
Total Revenues	2,225,896	1,469,868	415,771	88,723	68,441	183,093
Depreciation, depletion and amortization	458,878	402,033	15,674	5,933	10,367	24,871
Loss on derivative instruments	389,723	389,723	-	-	-	-
Income (loss) before taxes	849,455	484,655	373,490	59,250	52,851	(120,791)
Total assets at September 30, 2007 (1)	$ 10,251,428	$ 7,515,385	$ 1,222,046	$ 476,729	$ 265,026	$ 772,242
Total assets at December 31, 2006 (1)	9,588,625	7,224,920	960,357	343,236	256,913	803,199

(1) North America includes goodwill of $766 million and $781 million at September 30, 2007 and December 31, 2006, respectively.

Note 12 - Commitments and Contingencies

Legal Proceedings– We are among a group of eighteen defendants named in a lawsuit filed August 23, 2002 by Dore Energy Corporation under Docket Number 10-16202 in the 38th Judicial District Court, Cameron Parish, Louisiana. The lawsuit alleges damage to property owned by Dore resulting from oil and gas activities dating to the 1930's. Our predecessor, Samedan Oil Corporation, operated on a portion of the property from 1989 to 1999. This disclosure is being made due to Dore's recent delivery of documents alleging approximately $140 million in damages. We intend to vigorously defend against these allegations and believe that our share of damages, if any, will not have a material adverse effect on our results of operations, financial condition or liquidity.

The Illinois Environmental Protection Agency ("IEPA") issued a notice of violation to Equinox Oil Company on September 25, 2001 alleging violation of air emission and permitting regulations for a facility known as the Zif Gas Plant located near Clay City, Illinois. On January 17, 2007, the IEPA re-issued written notices of these alleged violations in the name of Equinox's successors in interest, and our wholly-owned subsidiaries, Elysium Energy, LLC and Noble Energy Production, Inc. On March 16, 2007, the IEPA accepted our compliance commitment agreement wherein we agreed to pay a delayed permit fee, install an incineration/caustic scrubber emissions control system at the site, and fund a supplemental environmental project ("SEP") in the nearby community. At this time, we expect no additional monies to be expended other than these amounts for which we have fully accrued. As of September 30, 2007, the emissions control system is operational and test information is being collected to provide to the IEPA. The initial SEP project has been completed.

We are involved in various legal proceedings in the ordinary course of business. These proceedings are subject to the uncertainties inherent in any litigation. We are defending ourselves vigorously in all such matters and we do not believe that the ultimate disposition of such proceedings will have a material adverse effect on our financial position, results of operations or cash flows.

Note 13 - Capitalized Exploratory Well Costs

Changes in capitalized exploratory well costs are as follows and exclude amounts that were capitalized and subsequently expensed in the same period.

		Nine Months Ended September 30, 2007 (in thousands)
Capitalized exploratory well costs at beginning of period	$	80,359
Additions to capitalized exploratory well costs pending determination of proved reserves		145,575
Reclassified to proved oil and gas properties based on determination of proved reserves		(4,595)
Capitalized exploratory well costs charged to expense		(6,454)
Capitalized exploratory well costs at end of period	$	214,885

The following table provides an aging of capitalized exploratory well costs based on the date the drilling was completed and the number of projects for which exploratory well costs have been capitalized for a period greater than one year since the completion of drilling:

	September 30, 2007	December 31, 2006
	(in thousands)	
Capitalized exploratory well costs that have been capitalized for a period of one year or less	$ 174,602	$ 58,493
Capitalized exploratory well costs that have been capitalized for a period greater than one year after completion of drilling	40,283	21,866
Balance at end of period	$ 214,885	$ 80,359
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year after completion of drilling	2	4

Exploratory well costs capitalized for more than one year at September 30, 2007 included two projects. One project relates to Blocks O and I, offshore Equatorial Guinea, and includes approximately $21 million of suspended exploratory well costs. Since drilling the initial well for the project, additional seismic work has been completed and appraisal wells are being drilled to further evaluate this potential discovery. The other project relates to Redrock (Mississippi Canyon Block 204), located in deepwater Gulf of Mexico, and includes approximately $19 million of suspended exploratory well costs. We are assessing the economic and operating viability of the well and are currently planning a side-track project which will facilitate tie-back options.

Note 14 - Recently Issued Pronouncements

SFAS 157 – In September 2006, the FASB issued SFAS 157, "Fair Value Measurements" ("SFAS 157"). SFAS 157 establishes a single authoritative definition of fair value based upon the assumptions market participants would use when pricing an asset or liability and creates a fair value hierarchy that prioritizes the information used to develop those assumptions. Under the standard, additional disclosures are required, including disclosures of fair value measurements by level within the fair value hierarchy. SFAS 157 is effective for fair value measures already required or permitted by other standards for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. We expect to adopt SFAS 157 on January 1, 2008 and are currently evaluating the provisions of SFAS 157 and assessing the impact it may have on our financial position and results of operations.

SFAS 159 – In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" ("SFAS 159"). SFAS 159 provides companies with an option to report selected financial assets and liabilities at fair value. SFAS 159 is effective as of the beginning of an entity's first fiscal year beginning after November 15, 2007. We are currently evaluating the provisions of SFAS 159 and assessing the impact it may have on our financial position and results of operations.

FSP FIN 39-1 – In April 2007, the FASB issued FSP FIN 39-1, "An Amendment of FASB Interpretation No. 39" ("FSP FIN 39-1"). FSP FIN 39-1 allows companies to offset fair value amounts recognized for derivative instruments and the fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral. The cash collateral must arise from derivative instruments recognized at fair value that are executed with the same counterparty under a master netting arrangement. A company must make an accounting policy decision whether or not to offset fair value amounts. FSP FIN 39-1 is effective for fiscal years beginning after November 15, 2007 and is to be applied retrospectively. We are currently evaluating the provisions of FSP FIN 39-1 and assessing the impact it may have on our financial position and results of operations.

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

EXECUTIVE OVERVIEW

We explore for and produce crude oil and natural gas on a worldwide basis. Our strategy is to achieve growth in earnings and cash flow through the development of a high quality portfolio of producing assets that is balanced between domestic and international projects.

Third quarter 2007 financial results included the following:

- net income of $223 million and diluted earnings per share of $1.28, as compared with net income of $318 million and diluted earnings per share of $1.75 for third quarter 2006 (which included the sale of our Gulf of Mexico shelf assets); and
- cash flow from operating activities of $548 million, as compared with $407 million for third quarter 2006.

Third quarter 2007 operational results included the following:

- oil discovery on Benita appraisal well on Block I, offshore Equatorial Guinea;
- successful appraisal well (Belinda) on Block O, offshore Equatorial Guinea;
- exploration success at the YoYo prospect on PH-77 license, offshore Cameroon;
- continued ramp-up of Dumbarton oil production in the North Sea;
- record quarterly natural gas production in Israel; and
- increasing natural gas sales to a liquefied natural gas ("LNG") plant in Equatorial Guinea.

In addition, we were the high bidder, subject to regulatory approval, on nine deepwater lease blocks at the Central Gulf of Mexico Outer Continental Shelf Sale 205 held in October 2007.

OUTLOOK

We expect crude oil and natural gas production to increase in 2007 compared to 2006. The expected year-over-year increase in production is impacted by several factors including:

- production contributions from the sale of natural gas from the Alba field in Equatorial Guinea to an LNG facility;
- the contribution of production from the Dumbarton North Sea development;
- growing natural gas sales in Israel due to the planned conversion of additional power plants to use natural gas as fuel;
- growing production from the Piceance Basin and the Niobrara Trend areas in the Northern region of our North America operations, where we are continuing active drilling programs;
- a full year of production from our acquisition of U.S. Exploration;
- partially offset by loss of production from Gulf of Mexico shelf assets sold in July 2006, natural field decline in the Gulf Coast area and specific well performance in the deepwater Gulf of Mexico.

Factors impacting our expected production profile for the remainder of 2007 include:

- infrastructure development in Israel;
- potential hurricane-related volume curtailments in the Gulf of Mexico and Gulf Coast areas;
- potential winter storm-related volume curtailments in the Northern region of our North America operations;
- potential pipeline and processing facility capacity constraints in the Rocky Mountain area of our Northern region;
- seasonal rainfall variations in Ecuador that affect our natural gas-to-power project;
- natural gas volume curtailments in Equatorial Guinea due to LNG plant repairs; and

- timing of capital expenditures, as discussed below, which are expected to result in near-term production.

2007 Capital Expenditures – We currently expect 2007 capital expenditures to total approximately $1.7 billion compared to the $1.4 billion announced in February of this year. The increases are primarily related to the acquisition and development of property in the Piceance Basin, acquisition of additional acreage in the Niobrara and New Albany Shale areas, leasing of offshore deepwater blocks in the Gulf of Mexico (subject to regulatory approval) and increases in our deepwater Gulf of Mexico and West Africa programs. The increase in deepwater Gulf of Mexico is primarily associated with the recent Isabela discovery, Raton development and Ticonderoga field development. Capital additions in West Africa are due to the addition of a second drilling rig which has now completed operations in Cameroon. Approximately 29% of the 2007 capital expenditures will be spent for exploration opportunities and 71% will be spent for production, development and other projects. On a geographic basis, approximately 77% of the capital expenditures will be domestic spending, 20% will be international spending and 3% will be corporate spending. Expected 2007 capital expenditures do not include the impact of possible additional asset purchases. We expect that our 2007 capital expenditures will be funded primarily from cash flows from operations and borrowings under our revolving credit facility. We will evaluate the level of capital spending throughout the year based upon drilling results, commodity prices, cash flows from operations, and property acquisitions and divestitures.

Recent Developments in Equatorial Guinea – Effective November 2006, the government of Equatorial Guinea enacted a new hydrocarbons law (the “2006 Hydrocarbons Law”) governing their domestic petroleum operations. The governmental agency overseeing the energy industry was given the authority to renegotiate any contract for the purpose of adapting any terms and conditions that are inconsistent with the new law. Our assessment of the impact of the change in the law remains ongoing, and we are working with various governmental authorities to determine the effect on our current contracts. However, at this time, the final impact of the 2006 Hydrocarbons Law on our operations in Equatorial Guinea remains uncertain.

Recently Issued Pronouncements – See Item 1. Financial Statements – Note 14 - Recently Issued Pronouncements.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Our primary cash needs are to fund capital expenditures related to the acquisition, exploration and development of crude oil and natural gas properties, to repay outstanding borrowings or to pay other contractual commitments and interest payments on debt. Traditional sources of our liquidity are cash on hand, cash flows from operations and available borrowing capacity under credit facilities. Occasional sales of non-strategic crude oil and natural gas assets may also generate funds. We had $451 million in cash and cash equivalents at September 30, 2007, compared with $153 million at December 31, 2006. Substantially all of this cash is located in our foreign subsidiaries and would be subject to additional US income taxes if repatriated. The cash is denominated in US dollars and is invested in highly liquid, investment-grade securities with maturities of three months or less at the time of purchase. We currently intend to use the cash located in our foreign subsidiaries to fund international projects, including the development of West Africa.

Cash Flows

Cash flow information is as follows:

	Nine Months Ended September 30,	
	2007	2006
	(in thousands)	
Total cash provided by (used in):		
Operating activities	$ 1,320,611	$ 1,340,813
Investing activities	(1,015,602)	(827,033)
Financing activities	(7,644)	(534,298)

Increase (decrease) in cash and cash equivalents	$ 297,365	$ (20,518)

Operating Activities– For the first nine months of 2007, we reported net cash provided by operating activities of $1.3 billion as compared with $1.3 billion for the first nine months of 2006. Significant factors impacting net cash provided by operating activities included:

- cash flows from higher liquid commodity prices; and
- dividends from equity method investees, which had been classified as investing cash flows in 2006 (See Item 2. Results of Operations – Equity Method Investees);

offset by:

- a decrease in non-cash working capital resulting from decreases in the current portions of asset retirement obligations and other accrued liabilities; and
- an increase in exploration costs, general and administrative expense and transportation costs.

Investing Activities – Net cash used in investing activities for the first nine months of 2007 totaled $1.0 billion, as compared with $827 million for the first nine months of 2006. Significant factors impacting net cash used in investing activities included:

- a slight decrease in capital expenditures during 2007 as compared to 2006;
- a decrease in acquisition and divestiture activity during 2007 as compared to the acquisition of U.S. Exploration and sale of our Gulf of Mexico shelf assets during 2006; and
- a decrease in distributions received from equity method investees for 2007 as compared to 2006 (See Item 2. Results of Operations – Equity Method Investees).

Financing Activities – Net cash used in financing activities for the first nine months of 2007 totaled $8 million, as compared with $534 million for the first nine months of 2006. As compared with the first nine months of 2006, financing activities for the first nine months of 2007 included:

- a net increase in cash from short-term and long-term borrowings in 2007 as compared with a net decrease from short-term and long-term borrowing repayments in 2006; and
- a reduction of cash used for repurchases of our common stock during the first nine months of 2007 as compared with the first nine months of 2006.

Acquisition, Capital and Other Exploration Expenditures

Acquisition, capital and other exploration expenditure information (on an accrual basis) is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(in thousands)			
Acquisition, Capital and Other Exploration Expenditures				
Lease acquisition of unproved property	$ 1,892	$ -	$ 93,346	$ 130,819
Lease acquisition of proved property	116	-	5,703	412,687
Exploration expenditures	97,407	51,819	249,973	192,896
Development expenditures	344,870	328,218	841,888	825,481
Corporate and other expenditures	4,847	5,866	23,662	15,948
Total	$ 449,132	$ 385,903	$ 1,214,572	$ 1,577,831

Insurance Recoveries

See Item I. Financial Statements - Note 6 – Effect of Gulf Coast Hurricanes.

Financing Activities

Long-Term Debt – Our long-term debt totaled $1.9 billion (excluding unamortized discount) at September 30, 2007. Maturities range from 2009 to 2097. Our ratio of debt-to-book capital was 30% at September 30, 2007 and December 31, 2006. We define our ratio of debt-to-book capital as total debt (which consists of long-term debt, excluding unamortized discount, plus short-term borrowings) divided by the sum of total debt plus equity.

Our principal source of liquidity is a $2.1 billion unsecured revolving credit facility (the "Credit Facility") due December 2011. The Credit Facility (i) provides for Credit Facility fee rates that range from 5 basis points to 15 basis points per year depending upon our credit rating, (ii) makes available swingline loans up to an aggregate amount of $300 million and (iii) provides for interest rates that are based upon the Eurodollar rate plus a margin that ranges from 20 basis points to 70 basis points depending upon our credit rating and utilization of the Credit Facility. The Credit Facility is with certain commercial lending institutions and is available for general corporate purposes. At September 30, 2007, $1.3 billion in borrowings were outstanding under the Credit Facility. The weighted average interest rate applicable to borrowings under the Credit Facility at September 30, 2007 was 5.77%.

We have $650 million of fixed-rate debt outstanding at September 30, 2007 with a weighted average interest rate of 6.92%. Maturities range from 2014 to 2097.

Piceance Installment Payments Due – During second quarter 2007, we purchased working interests in oil and gas properties in the Piceance Basin of western Colorado for $75 million. After making an initial cash payment of $25 million, we owe $50 million in the form of installment payments to the seller. Installments of $25 million each are due on May 12, 2008 and May 11, 2009. The amount due in 2008 is included in short-term borrowings and the amount due in 2009 is included in long-term debt in the consolidated balance sheets. Interest on the unpaid amounts is due quarterly. Interest accrues at a three-month LIBOR rate plus a margin. The interest rate was 5.66% at September 30, 2007.

Other Short-Term Borrowings – Our Credit Facility is supplemented by short-term borrowings under various uncommitted credit lines used for working capital purposes. Uncommitted credit lines may be offered by certain banks from time to time at rates negotiated at the time of borrowing. There were no borrowings outstanding under uncommitted credit lines at September 30, 2007.

Dividends – We paid quarterly cash dividends of 12 cents per share of common stock during third quarter 2007 as compared with 7.5 cents per share of common stock during third quarter 2006. For the first nine months of 2007, we paid total cash dividends of 31.5 cents per share of common stock as compared with 20 cents per share of common stock for the first nine months of 2006. On October 23, 2007, our Board of Directors declared a quarterly cash dividend of 12 cents per common share, payable November 19, 2007 to shareholders of record on November 5, 2007. The amount of future dividends will be determined on a quarterly basis at the discretion of our Board of Directors and will depend on earnings, financial condition, capital requirements and other factors.

Exercise of Stock Options – We received $4 million from the exercise of stock options during third quarter of 2007 as compared with $21 million during third quarter 2006 and $19 million during the first nine months of 2007 as compared with $51 million during the first nine months of 2006.

RESULTS OF OPERATIONS

Natural Gas Information

Natural gas sales increased 2% during third quarter 2007 as compared with third quarter 2006 due to a 25% increase in sales volumes offset by a 19% decline in average realized sales prices. Natural gas sales increased 2% for the first nine months of 2007 as compared with 2006 due to an 8% increase in sales volumes offset by a 5% decrease in average realized sales prices. Natural gas sales were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(in thousands)			
Natural gas sales	$ 296,360	$ 290,845	$ 935,364	$ 917,673

Natural gas sales are net of the effects of the settlement of derivative contracts that are accounted for as cash flow hedges. Natural gas sales in 2007 also include non-cash increases related to hedge contracts that were re-designated at the time of the Gulf of Mexico shelf asset sale in 2006 and settled during the first nine months of 2007. These non-cash increases totaled $42 million for third quarter 2007 and $133 million for the first nine months of 2007.

Average daily natural gas sales volumes and average realized sales prices were as follows:

	2007		2006	
	Mcfpd	$/Mcf	Mcfpd	$/Mcf
Three Months Ended September 30,				
North America (1)	404,238	$ 6.77	430,072	$ 6.41
West Africa (2) (3)	207,501	0.27	40,498	0.39
North Sea	5,496	7.26	8,553	6.62
Israel	131,115	2.95	116,718	2.84
Ecuador (4)	24,844	-	20,131	-
Other International	-	-	198	1.51
Total	773,194	$ 4.30	616,170	$ 5.30
Nine Months Ended September 30,				
North America (1)	410,083	$ 7.42	461,843	$ 6.55
West Africa (2) (3)	126,820	0.29	44,232	0.38
North Sea	5,967	6.05	8,460	8.13
Israel	110,675	2.81	91,656	2.74
Ecuador (4)	25,571	-	22,764	-
Other International	-	-	324	1.20
Total	679,116	$ 5.24	629,279	$ 5.54

(1) Average realized sales prices include the effects of hedging activities. Hedging activities resulted in increases (reductions) per Mcf of $1.29 and $0.07 for third quarter 2007 and 2006, respectively, and $1.07 and $(0.47) for the first nine months of 2007 and 2006, respectively.

(2) Natural gas from the Alba field in Equatorial Guinea is under contract for $0.25 per MMBtu to a methanol plant, an LPG plant and an LNG plant. The price on an Mcf basis has been adjusted to reflect Btu content. The methanol and LPG plants are owned by affiliated entities accounted for under the equity method of accounting. The volumes sold by the LPG plant are included in the table below under crude oil information.

(3) Equatorial Guinea natural gas volumes include sales to an LNG plant of 154,637 Mcfpd for third quarter 2007 and 72,010 Mcfpd for the first nine months of 2007. There were no natural gas sales to the LNG plant in 2006.

(4) The natural gas-to-power project in Ecuador is 100% owned by our subsidiaries and intercompany natural gas sales are eliminated for accounting purposes. Electricity sales of $54 million and $50 million are included in other revenues for the first nine months of 2007 and 2006, respectively.

Factors contributing to the increase in natural gas sales volumes for the third quarter and first nine months of 2007 as compared with 2006 included:

- sales of natural gas to an LNG facility in Equatorial Guinea;
- a full nine months of production from U.S. Exploration properties and successful development activity in the Northern region of our North America operations; and
- a full nine months of sales to Israeli Electric Company's Reading power plant in Tel Aviv, as well as increased seasonal demand for electricity;

offset by:

- reduction due to sale of our Gulf of Mexico shelf assets in 2006;
- a temporary decline in production due to third party processing downtime and inclement weather in the Northern region of our North America operations;
- natural field decline in the Gulf Coast area; and
- declining performance and storm shut-in in the deepwater Gulf of Mexico.

Crude Oil Information

Crude oil sales increased 15% for third quarter 2007 as compared with third quarter 2007 due to a 7% increase in total consolidated sales volumes and a 7% increase in average realized sales prices. Crude oil sales increased 7% for the first nine months of 2007 as compared with 2006 due to a 4% increase in total consolidated sales volumes and a 3% increase in average realized sales prices. Crude oil sales were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(in thousands)			
Crude oil sales	$ 449,898	$ 392,699	$ 1,204,854	$ 1,126,983

Crude oil sales are net of the effects of the settlement of derivative contracts that are accounted for as cash flow hedges. Average daily crude oil production and sales volumes and average realized sales prices were as follows:

	2007			2006		
	Production (1) Bopd	Sales Bopd	$/Bbl	Production (1) Bopd	Sales Bopd	$/Bbl
Three Months Ended September 30,						
North America (2)	39,992	39,992	$ 55.85	48,193	48,193	$ 56.84
West Africa (3)	15,327	13,757	73.25	17,324	13,649	66.93
North Sea	15,722	16,644	77.13	3,675	3,292	68.90
Other International	6,630	6,578	55.55	7,783	6,825	56.96
Total Consolidated Operations	77,671	76,971	63.53	76,975	71,959	59.32
Equity Investees (4)	7,949	7,472	57.24	7,994	8,932	48.88
Total	85,620	84,443	$ 62.98	84,969	80,891	$ 58.17
Nine Months Ended September 30,						
North America (2)	43,525	43,525	$ 51.04	45,834	45,834	$ 51.48
West Africa (3)	15,874	14,936	66.97	17,790	17,374	63.73
North Sea	11,954	11,926	70.41	3,867	3,619	70.79
Other International	7,043	6,998	50.30	7,338	7,463	54.31
Total Consolidated Operations	78,396	77,385	57.03	74,829	74,290	55.57
Equity Investees (4)	8,220	7,862	50.93	7,503	8,168	46.96

Total	86,616	85,247	$	56.47	82,332	82,458	$	54.72

(1) The variance between production and sales volumes is attributable to the timing of liquid hydrocarbon tanker liftings.
(2) Average realized sales prices include the effects of hedging activities. Hedging activities resulted in reductions per Bbl of $15.64 and $10.46 for third quarter 2007 and 2006, respectively, and $10.57 and $12.76 for the first nine months of 2007 and 2006, respectively.
(3) Average realized sales prices include the effects of hedging activities. Hedging activities resulted in reductions per Bbl of $2.18 for third quarter 2007 and $0.68 for the first nine months of 2007.
(4) Volumes represent our share of sales of condensate and LPG from the Alba plant in Equatorial Guinea. LPG volumes were 5,530 Bpd and 6,957 Bpd for third quarter 2007 and 2006, respectively, and 5,907 Bopd and 6,409 Bopd for the first nine months of 2007 and 2006, respectively.

Factors contributing to the increases in crude oil sales volumes for the third quarter and first nine months of 2007 as compared with 2006 included:

- contribution of Dumbarton North Sea development;
- a full nine months of production from U.S. Exploration properties; and
- successful development activity in the Northern region of our North America operations;

offset by:

- reduction due to sale our of Gulf of Mexico shelf assets in 2006;
- timing of liftings in Equatorial Guinea;
- temporary decline in production due to inclement weather in the Northern region;
- natural field decline in the Gulf Coast area; and
- declining performance and storm shut-in in the deepwater Gulf of Mexico.

Effect of Hedging Activities

We hedge varying portions of forecasted future crude oil and natural gas sales to reduce the exposure to commodity price fluctuations. Revenues from oil and gas sales include the results of crude oil and natural gas cash flow hedging activities. Cash flow hedging activities decreased oil and gas sales by $12 million and $44 million for third quarter 2007 and 2006, respectively, and $8 million and $219 million for the first nine months of 2007 and 2006, respectively. See Item I. Financial Statements - Note 3 – Derivative Instruments and Hedging Activities.

Equity Method Investees

Our share of operations of equity method investees was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Net income (in thousands):				
AMPCO and affiliates	$ 14,649	$ 3,302	$ 50,404	$ 27,415
Alba Plant	$ 30,722	$ 30,508	$ 89,500	$ 81,486
Distributions/Dividends (in thousands):				
AMPCO and affiliates	$ 17,513	$ -	$ 59,920	$ 19,500
Alba Plant	$ 40,975	$ 39,001	$ 95,511	$ 115,021
Sales volumes:				
Methanol (Kgal)	43,541	18,769	116,792	85,233
Condensate (Bopd)	1,942	1,975	1,955	1,759
LPG (Bpd)	5,530	6,957	5,907	6,409
Production volumes:				
Condensate (Bopd)	1,815	1,811	1,896	1,726
LPG (Bpd)	6,134	6,183	6,324	5,777

Average realized prices:				
Methanol (per gallon)	$ 0.80	$ 0.83	$ 0.96	$ 0.83
Condensate (per Bbl)	$ 77.91	$ 69.46	$ 69.63	$ 67.51
LPG (per Bbl)	$ 49.98	$ 43.03	$ 44.75	$ 41.32

For third quarter 2007, net income from AMPCO and affiliates increased substantially relative to 2006 due to a more than twofold increase in methanol sales volumes. For the first nine months of 2007, net income from AMPCO and affiliates increased 84% relative to 2006 due to a 37% increase in methanol sales volumes and a 16% increase in average realized methanol prices. The increase in methanol sales volumes for both the three months and nine months ended September 30, 2007 was due to a 57-day shutdown of methanol production for the plant turnaround that occurred during May and June 2006 followed by 35 days of compressor repairs.

For third quarter 2007, net income from Alba Plant increased 1% relative to 2006 due to a 16% increase in average realized LPG prices and a 12% increase in average realized condensate prices offset by a 21% decrease in LPG sales volumes. The decrease in LPG sales volumes for the three months ended September 30, 2007 was due to the timing of liftings. For the first nine months of 2007, net income from Alba Plant increased 10% relative to 2006 due to an 11% increase in condensate sales volumes and an 8% increase in average realized LPG prices offset by an 8% decrease in LPG sales volumes.

For the first nine months of 2007, $96 million received from Alba Plant was classified within operating cash flows as a dividend from equity method investee as compared with the first nine months of 2006 in which the distributions were classified within investing cash flows as a repayment of a loan. The change in classification was the result of all outstanding loans being repaid to us by Alba Plant in December 2006.

Costs and Expenses

Production Costs – Production costs were as follows:

	Consolidated	North America	West Africa	North Sea	Israel	Other Int'l / Corporate[2]
			(in thousands)			
Three Months Ended September 30, 2007						
Oil and gas operating costs [1]	$ 77,283	$ 50,007	$ 7,483	$ 10,697	$ 2,615	$ 6,481
Workover and repair expense	4,484	4,460	-	-	-	24
Lease operating expense	81,767	54,467	7,483	10,697	2,615	6,505
Production and ad valorem taxes	26,752	21,389	-	-	-	5,363
Transportation costs	13,260	10,111	-	2,859	-	290
Total production costs	$ 121,779	$ 85,967	$ 7,483	$ 13,556	$ 2,615	$ 12,158
Three Months Ended September 30, 2006						
Oil and gas operating costs [1]	$ 66,431	$ 50,753	$ 6,310	$ 3,355	$ 2,134	$ 3,879
Workover and repair expense	10,497	10,453	-	-	-	44
Lease operating expense	76,928	61,206	6,310	3,355	2,134	3,923
Production and ad valorem taxes	30,697	22,636	-	-	-	8,061
Transportation costs	4,531	3,358	-	952	-	221
Total production costs	$ 112,156	$ 87,200	$ 6,310	$ 4,307	$ 2,134	$ 12,205
Nine Months Ended September 30, 2007						
Oil and gas operating costs [1]	$ 228,672	$ 155,980	$ 25,014	$ 23,954	$ 6,896	$ 16,828
Workover and repair expense	14,533	14,327	-	-	-	206
Lease operating expense	243,205	170,307	25,014	23,954	6,896	17,034
Production and ad valorem taxes	80,667	65,933	-	-	-	14,734
Transportation costs	40,346	31,887	-	7,091	-	1,368
Total production costs	$ 364,218	$ 268,127	$ 25,014	$ 31,045	$ 6,896	$ 33,136
Nine Months Ended September 30, 2006						
Oil and gas operating costs [1]	$ 195,550	$ 147,357	$ 21,760	$ 7,998	$ 6,389	$ 12,046
Workover and repair expense	42,757	42,628	-	-	-	129
Lease operating expense	238,307	189,985	21,760	7,998	6,389	12,175
Production and ad valorem taxes	83,663	66,373	-	-	-	17,290
Transportation costs	18,463	14,022	-	3,843	-	598
Total production costs	$ 340,433	$ 270,380	$ 21,760	$ 11,841	$ 6,389	$ 30,063

(1) Oil and gas operating costs include labor, fuel, repairs, replacements, saltwater disposal and other related lifting costs.

(2) Other international includes Ecuador, China, and Argentina.

Oil and gas operating costs increased $11 million, or 16%, third quarter 2007, as compared with third quarter 2006, and increased $33 million, or 17%, for the first nine months of 2007, as compared with the first nine months of 2006. The increases are primarily the result of expanded operations in the North Sea, the deepwater Gulf of Mexico and the Rocky Mountain and Mid-continent areas of our North America operations. In addition, the first nine months of 2007 includes increased expense, including snow removal cost, related to severe winter weather in the Northern region.

Workover and repair expense decreased $6 million for third quarter 2007 and decreased $28 million for the first nine months of 2007, as compared with 2006. The decrease was due to a reduction in hurricane-related repair expense.

Hurricane-related repair expense was de minimis for third quarter 2007 and $1 million for the first nine months of 2007, as compared with $4 million for third quarter 2006 and $26 million for the first nine months of 2006.

Transportation costs increased third quarter 2007 and the first nine months of 2007, as compared with 2006, primarily due to changes in the terms of certain sales contracts for Northern region production.

Selected expenses on a per BOE sales volume basis were as follows (Natural gas volumes are converted to oil equivalent volumes on the basis of six Mcf per barrel.):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Oil and gas operating costs	$ 4.08	$ 4.14	$ 4.40	$ 4.00
Workover and repair expense	0.24	0.65	0.28	0.87
Lease operating expense	4.32	4.79	4.68	4.87
Production and ad valorem taxes	1.41	1.91	1.55	1.71
Transportation costs	0.70	0.28	0.78	0.38
Total production costs (1)	$ 6.43	$ 6.98	$ 7.01	$ 6.96

(1) Consolidated unit rates exclude sales volumes and costs attributable to equity method investees. The sales volumes include natural gas sales to the Equatorial Guinea LNG plant that began late first quarter of 2007. The inclusion of these volumes reduced the unit rates by $0.92 per BOE and $0.47 per BOE for the three and nine months ending September 30, 2007, respectively.

The changes in the unit rates of total production costs are primarily due to the impact of the mix of sales volumes. Workover and repair costs per BOE decreased in 2007 due to a reduction in hurricane-related repair expense.

Oil and Gas Exploration Expense – Oil and gas exploration expense consists of dry hole expense, unproved lease amortization, seismic expense, staff expense and other miscellaneous exploration expense, including lease rentals. Oil and gas exploration expense was $46 million for third quarter 2007, as compared with $31 million for third quarter 2006. The increase was due to a $10 million increase in seismic expenditures primarily for the Gulf of Mexico and an $8 million increase in dry hole expense in West Africa, offset by a $2 million decrease in undeveloped leasehold amortization. Oil and gas exploration expense was $145 million for the first nine months of 2007, as compared with $92 million for the first nine months of 2006. The increases were due to a $27 million increase in seismic expenditures primarily for the Gulf of Mexico and North Sea, a $24 million increase in dry hole expense in West Africa, and a $5 million increase in staff expense for new venture activity, offset by a $2 million decrease in undeveloped leasehold amortization.

Depreciation, Depletion and Amortization – Depreciation, depletion and amortization (“DD&A”) expense was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
DD&A expense (in thousands)	$ 195,266	$ 165,765	$ 540,453	$ 458,878
Unit rate per BOE sales volume (1)	$ 10.31	$ 10.32	$ 10.39	$ 9.38

(1) Consolidated unit rates exclude sales volumes and costs attributable to equity method investees. The sales volumes include natural gas sales to the Equatorial Guinea LNG plant that began late first quarter of 2007. The inclusion of these volumes reduced the unit rates by $1.20 per BOE and $0.57 per BOE for the three and nine months ending September 30, 2007, respectively.

DD&A expense for third quarter 2007 increased as compared with 2006 due to higher sales volumes in the North Sea, Equatorial Guinea and Israel. DD&A expense for the first nine months of 2007 increased as compared with 2006 due to higher sales volumes in the North Sea, Equatorial Guinea and Israel and also due to higher DD&A rates. The increase in the unit rate was primarily due to higher finding and development costs in the Northern region of our North America operations and the Dumbarton North Sea development.

General and Administrative Expense– General and administrative expense ("G&A") was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
G&A expense (in thousands)	$ 49,518	$ 40,657	$ 142,368	$ 113,716
Unit rate per BOE sales volume [1]	$ 2.61	$ 2.53	$ 2.74	$ 2.32

[1] Consolidated unit rates exclude sales volumes and costs attributable to equity method investees. The sales volumes include natural gas sales to the Equatorial Guinea LNG plant that began late first quarter of 2007. The inclusion of these volumes reduced the unit rates by $0.38 per BOE and $0.18 per BOE for the three and nine months ending September 30, 2007, respectively.

G&A expense for third quarter and the first nine months of 2007 increased as compared with 2006 primarily due to higher salaries and wages resulting from an increase in the number of employees to address our increased activities. G&A expense includes stock-based compensation expense of $8 million and $3 million for third quarter 2007 and 2006, respectively, and $19 million and $9 million for the first nine months of 2007 and 2006, respectively. Stock-based compensation expense increased in 2007 as compared with 2006 due to an increase in the quantity and fair market values of stock-based awards.

Interest Expense and Capitalized Interest – Interest expense, net of interest capitalized, was $29 million for third quarter 2007 and 2006. For the first nine months of 2007, interest expense, net of interest capitalized, decreased to $87 million, from $96 million for the first nine months of 2006. Capitalized interest was $4 million and $1 million for third quarter 2007 and 2006, respectively, and $10 million and $3 million for the first nine months of 2007 and 2006, respectively. Interest expense, net of interest capitalized, decreased in 2007 due to a lower average outstanding debt balance.

(Gain) Loss on Derivative Instruments – See Item I. Financial Statements - Note 3 – Derivative Instruments and Hedging Activities.

Gain on Sale of Assets– Third quarter 2006 includes a pretax gain of $204 million from the sale of substantially all of our Gulf of Mexico shelf assets.

Other Expense, Net – See Item I. Financial Statements - Note 2 – Basis of Presentation.

Income Tax Provision – The income tax provision was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Income tax provision (in thousands)	$ 120,602	$ 226,902	$ 296,638	$ 336,009
Effective rate	35.1%	41.6%	31.5%	39.6%

Tax expense was higher in 2006 because $100 million of goodwill associated with the sale of the Gulf of Mexico shelf assets was not deductible, there was an increase in the valuation allowance on a deferred tax asset for future foreign tax credits and there was an increase in deferred tax liabilities due to a rate change in the UK. In addition, income from equity method investments was higher in 2007, which is a favorable permanent difference in calculating income tax expense.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

Derivative Instruments Held for Non-Trading Purposes– We are exposed to market risk in the normal course of business operations. We believe that we are well positioned with our mix of crude oil and natural gas reserves to take advantage of future price increases that may occur. However, the uncertainty of crude oil and natural gas prices continues to impact the oil and gas industry. Due to the volatility of crude oil and natural gas prices, we continue to use derivative instruments as a means of managing our exposure to commodity price changes.

At September 30, 2007, we had entered into variable to fixed price swaps, costless collars and basis swaps related to crude oil and natural gas sales. See Item 1. Financial Statements - Note 3 – Derivative Instruments and Hedging Activities.

At September 30, 2007, we had a net unrealized loss of $229 million (pre-tax) related to crude oil and natural gas derivative instruments entered into for hedging purposes. A net unrealized loss of $143 million, net of tax, is recorded in AOCL in the shareholders' equity section in the consolidated balance sheets. We will reclassify the loss to earnings as adjustments to revenue when future sales occur.

Interest Rate Risk

We are exposed to interest rate risk related to our variable and fixed interest rate debt. At September 30, 2007, we had $1.9 billion (excluding unamortized discount) of long-term debt outstanding, of which $650 million was fixed-rate debt. The weighted average interest rate on our fixed-rate debt was 6.92% at September 30, 2007. We believe that anticipated near term changes in interest rates would not have a material effect on the fair value of our fixed-rate debt and would not expose us to the risk of material earnings or cash flow loss.

At September 30, 2007, we had $1.3 billion of long-term variable-rate debt and $25 million of short-term variable-rate debt outstanding. Variable rate debt exposes us to the risk of earnings or cash flow loss due to changes in market interest rates. We estimate that a hypothetical 10% change in the floating interest rates applicable to our September 30, 2007 balance of variable-rate debt would result in a change in annual interest expense of approximately $8 million.

Foreign Currency Risk

We have not entered into foreign currency derivatives. Transactions that are completed in a foreign currency are remeasured into US dollars and recorded in the financial statements at prevailing currency exchange rates. We do not have any significant monetary assets or liabilities denominated in a foreign currency and consequently transaction gains or losses are not material in any of the periods presented. We do not believe we are currently exposed to any material risk of loss on this basis. Such gains or losses are included in other expense, net on the statements of operations.

DISCLOSURE REGARDING FORWARD-LOOKING STATEMENTS

This quarterly report on Form 10-Q contains forward-looking statements within the meaning of the federal securities laws. Forward-looking statements give our current expectations or forecasts of future events. These forward-looking statements include, among others, the following:

- our growth strategies;
- our ability to successfully and economically explore for and develop crude oil and natural gas resources;

- anticipated trends in our business;
- our future results of operations;
- our liquidity and ability to finance our exploration and development activities;
- market conditions in the oil and gas industry;
- our ability to make and integrate acquisitions; and

- the impact of governmental regulation.

Forward-looking statements are typically identified by use of terms such as “may,” “will,” “expect,” “anticipate,” “estimate” an similar words, although some forward-looking statements may be expressed differently. These forward-looking statements are made based upon management’s current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve a number of risks and uncertainties. We caution that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements. You should consider carefully the statements under Item 1A. Risk Factors included herein and included in our 2006 annual report on Form 10-K, which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements. Our 2006 annual report on Form 10-K is available on our website at www.nobleenergyinc.com.

ITEM 4. CONTROLS AND PROCEDURES

Based on the evaluation of our disclosure controls and procedures by Charles D. Davidson, our principal executive officer, and Chris Tong, our principal financial officer, as of the end of the period covered by this quarterly report, each of them has concluded that our disclosure controls and procedures, as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended, are effective. There were no changes in internal control over financial reporting that occurred during the quarter covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION
ITEM 1. LEGAL PROCEEDINGS

See Item I. Financial Statements - Note 12 – Commitments and Contingencies.

ITEM 1A. RISK FACTORS

There have been no material changes from the risk factors disclosed in Item 1A. Risk Factors of our Annual Report on Form 10-K for the year ended December 31, 2006 other than the following:

Information technology systems implementation issues could disrupt our internal operations and adversely affect our financial results or our ability to report our financial results.

We are currently in the process of implementing a new Enterprise Resource Planning software system to replace our various legacy systems. Our implementation is based on a phased approach and we expect to have the first phase implemented by the end of 2007. As a part of this effort, we are transitioning data and changing processes and this may be more expensive, time consuming and resource intensive than planned. Any disruptions that may occur in the implementation or operation of this system or any future systems could increase our expenses and adversely affect our ability to report in an accurate and timely manner our financial position, results of operations and cash flows and to otherwise operate our business.

ITEM 6. EXHIBITS

The information required by this Item 6 is set forth in the Index to Exhibits accompanying this quarterly report on Form 10-Q.

SIGNATURES

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

NOBLE ENERGY, INC.
(Registrant)

Date October 31, 2007	/s/ CHRIS TONG CHRIS TONG Senior Vice President and Chief Financial Officer

INDEX TO EXHIBITS

Exhibit Number	Exhibit
31.1	Certification of the Company's Chief Executive Officer Pursuant To Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241).
31.2	Certification of the Company's Chief Financial Officer Pursuant To Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241).
32.1	Certification of the Company's Chief Executive Officer Pursuant To Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350).
32.2	Certification of the Company's Chief Financial Officer Pursuant To Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350).