NOBLE ENERGY INC
Form 10-Q
August 02, 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 June 30, 2007

OR

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

For the transition period from _______ to _______

Commission file 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 July 25, 2007: 171,116,188

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

Noble Energy, Inc. and Subsidiaries

Consolidated Balance Sheets

(in thousands, except share amounts)

	(Unaudited) June 30, 2007	December 31, 2006
ASSETS		
Current Assets		
Cash and cash equivalents	$ 301,750	$ 153,408
Accounts receivable - trade, net	603,094	586,882
Deferred income taxes	50,912	99,835
Probable insurance claims	30,620	101,233
Other current assets	141,431	127,188
Total current assets	1,127,807	1,068,546
Property, plant and equipment		
Oil and gas properties (successful efforts method of accounting)	9,539,419	8,867,639
Other property, plant and equipment	90,534	79,646
	9,629,953	8,947,285
Accumulated depreciation, depletion and amortization	(2,110,142)	(1,776,528)
Total property, plant and equipment, net	7,519,811	7,170,757
Other noncurrent assets	574,321	568,032
Goodwill	767,121	781,290
Total Assets	$ 9,989,060	$ 9,588,625
LIABILITIES AND SHAREHOLDERS EQUITY		
Current Liabilities		
Accounts payable - trade	$ 548,147	$ 518,609
Derivative instruments	328,418	254,625
Income taxes	36,616	107,136
Short-term borrowings	40,000	
Asset retirement obligations	44,189	68,500
Other current liabilities	166,581	235,392
Total current liabilities	1,163,951	1,184,262
Deferred income taxes	1,771,059	1,758,452
Asset retirement obligations	111,471	127,689
Derivative instruments	223,854	328,875
Other noncurrent liabilities	342,048	274,720
Long-term debt	1,990,949	1,800,810
Total Liabilities	5,603,332	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; 190,244,402 and 188,808,087 shares issued, respectively	634,151	629,360
Capital in excess of par value	2,074,136	2,041,048
Accumulated other comprehensive loss	(192,196)	(140,509)
	(612,976)	(511,443)

Treasury stock, at cost: 18,580,865 and 16,574,384 shares, respectively		
Retained earnings	2,482,613	2,095,361
Total Shareholders Equity	4,385,728	4,113,817
Total Liabilities and Shareholders Equity	$ 9,989,060	$ 9,588,625

The accompanying notes are an integral part of these financial statements

Noble Energy, Inc. and Subsidiaries

Consolidated Statements of Operations

(in thousands, except per share amounts)

(Unaudited)

	Three Months Ended June 30, 2007	2006	Six Months Ended June 30, 2007	2006
Revenues				
Oil and gas sales	$ 726,918	$ 714,860	$ 1,393,960	$ 1,361,112
Income from equity method investees	48,970	35,441	94,533	75,091
Other revenues	18,325	22,279	48,265	48,374
Total Revenues	794,213	772,580	1,536,758	1,484,577
Costs and Expenses				
Lease operating costs	82,563	79,186	161,438	161,379
Production and ad valorem taxes	28,748	27,513	53,915	52,966
Transportation costs	16,052	8,871	27,086	13,932
Exploration costs	53,761	29,400	99,002	61,423
Depreciation, depletion and amortization	181,227	168,648	345,187	293,113
General and administrative	47,761	37,661	92,850	73,059
Accretion of discount on asset retirement obligations	2,041	2,662	4,428	5,979
Interest, net of amount capitalized	30,986	33,918	57,858	67,086
(Gain) loss on derivative instruments	(1,066)	401,197	(2,071)	396,039
Loss on involuntary conversion	38,291		51,406	
Other expense, net	20,748	28,389	48,706	55,112
Total Costs and Expenses	501,112	817,445	939,805	1,180,088
Income (Loss) Before Taxes	293,101	(44,865)	596,953	304,489
Income Tax Provision (Benefit)	83,996	(14,160)	176,036	109,107
Net Income (Loss)	$ 209,105	$ (30,705)	$ 420,917	$ 195,382
Earnings (Loss) Per Share				
Basic	$ 1.22	$ (0.17)	$ 2.46	$ 1.11
Diluted	$ 1.21	$ (0.17)	$ 2.43	$ 1.08
Weighted average number of shares outstanding				
Basic	170,900	177,160	170,873	176,651
Diluted	173,083	177,160	173,064	180,460

The accompanying notes are an integral part of these financial statements

Noble Energy, Inc. and Subsidiaries

Consolidated Statements of Cash Flows

(in thousands)

(Unaudited)

	Six Months Ended June 30, 2007	2006
Cash Flows From Operating Activities		
Net income	$ 420,917	$ 195,382
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization - oil and gas production	345,187	293,113
Depreciation, depletion and amortization - electricity generation	6,913	8,067
Dry hole expense	30,863	15,019
Impairment of operating assets		6,359
Amortization of unproved leasehold costs	9,490	10,086
Stock-based compensation expense	12,078	6,323
Gain on sale of assets	(6,065)	(11,015)
Deferred income taxes	103,516	47,059
Accretion of discount on asset retirement obligations	4,428	5,979
Income from equity method investees	(94,533)	(75,091)
Dividends received from equity method investees	96,944	18,000
Deferred compensation expense	14,666	14,740
(Gain) loss on derivative instruments	(92,690)	447,789
Loss on involuntary conversion	51,406	
Other	61,045	8,440
Changes in operating assets and liabilities, net of acquisition:		
Increase in accounts receivable	(22,498)	(69,810)
Increase in other current assets	(36,270)	(30,800)
Decrease in probable insurance claims	73,478	91,560
Increase in accounts payable	29,538	33,596
Decrease in other current liabilities	(235,542)	(80,556)
Net Cash Provided by Operating Activities	772,871	934,240
Cash Flows From Investing Activities		
Additions to property, plant and equipment	(695,132)	(629,860)
U.S. Exploration acquisition, net of cash acquired		(412,257)
Proceeds from property sales		16,928
Investment in equity method investees		(1,358)
Distributions from equity method investees		77,520
Net Cash Used in Investing Activities	(695,132)	(949,027)
Cash Flows From Financing Activities		
Exercise of stock options	15,597	29,289
Tax benefits from stock-based awards	10,204	7,600
Cash dividends paid	(33,665)	(22,350)
Purchases of treasury stock	(101,533)	(23,682)
Proceeds from credit facility	280,000	300,000
Repayment of credit facility	(115,000)	(210,000)
Repayment of term loans		(80,000)
Proceeds from short term borrowings	15,000	85,000
Net Cash Provided by Financing Activities	70,603	85,857
Increase in Cash and Cash Equivalents	148,342	71,070
Cash and Cash Equivalents at Beginning of Period	153,408	110,321
Cash and Cash Equivalents at End of Period	$ 301,750	$ 181,391

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	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	$ 629,360	$ 2,041,048	$	$ (140,509)	$ (511,443)	$ 2,095,361	$ 4,113,817
Net income						420,917	420,917
Stock-based compensation expense		12,078					12,078
Exercise of stock options	3,044	12,553					15,597
Tax benefits from stock-based awards		10,204					10,204
Issuance of restricted stock, net	1,747	(1,747)					
Dividends ($0.195 per share)						(33,665)	(33,665)
Purchases of treasury stock					(101,533)		(101,533)
Oil and gas cash flow hedges:							
Realized amounts reclassified into earnings				(2,510)			(2,510)
Unrealized change in fair value				(51,372)			(51,372)
Net change in other				2,195			2,195
June 30, 2007	$ 634,151	$ 2,074,136	$	$ (192,196)	$ (612,976)	$ 2,482,613	$ 4,385,728
December 31, 2005	$ 616,311	$ 1,945,239	$ (5,288)	$ (783,499)	$ (148,476)	$ 1,465,857	$ 3,090,144
Net income						195,382	195,382
Adoption of SFAS 123(R), net of tax		(5,288)	5,288				
Stock-based compensation expense		6,323					6,323
Exercise of stock options	5,169	24,120					29,289
Tax benefits from stock-based awards		7,600					7,600
Issuance of restricted stock, net	217	(217)					
Dividends ($0.125 per share)						(22,350)	(22,350)
Rabbi trust shares sold		3,035			13,809		16,844
Purchases of treasury stock					(23,682)		(23,682)
Oil and gas cash flow hedges:							
Realized amounts reclassified into earnings				113,904			113,904
Unrealized amounts reclassified into earnings				275,542			275,542
Unrealized change in fair value				(5,121)			(5,121)
Net change in other				326			326
June 30, 2006	$ 621,697	$ 1,980,812	$	$ (398,848)	$ (158,349)	$ 1,638,889	$ 3,684,201

The accompanying notes are an integral part of these financial statements

Noble Energy, Inc. and Subsidiaries

Consolidated Statements of Comprehensive Income

(in thousands)

(Unaudited)

	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2007	**2006**	**2007**	**2006**
Net income (loss)	$ 209,105	$ (30,705)	$ 420,917	$ 195,382
Other items of comprehensive income (loss)				
Oil and gas cash flow hedges:				
Realized amounts reclassified into earnings	10,714	67,920	(4,022)	175,237
Less tax provision	(4,029)	(23,772)	1,512	(61,333)
Unrealized amounts reclassified into earnings		398,517		423,910
Less tax provision		(139,482)		(148,368)
Unrealized change in fair value	17,943	(75,603)	(82,327)	(7,878)
Less tax provision	(6,747)	26,462	30,955	2,757
Net change in other:	2,179	58	3,519	501
Less tax provision	(820)	(20)	(1,324)	(175)
Other comprehensive income (loss)	19,240	254,080	(51,687)	384,651
Comprehensive income	$ 228,345	$ 223,375	$ 369,230	$ 580,033

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 U.S. including Colorado s Wattenberg field, the Mid-continent region of western Oklahoma and the Texas Panhandle, the San Juan Basin in New Mexico, the Gulf Coast and the 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 U.S. 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 U.S. generally accepted accounting principles (GAAP) for complete financial statements. The accompanying unaudited consolidated financial statements at June 30, 2007 and December 31, 2006 and for the three and six months ended June 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 six months ended June 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.

Recent Acreage Acquisitions During second quarter 2007, we acquired approximately 280,000 net acres onshore North America in the Piceance, Niobrara and New Albany Shale areas at a cost of approximately $85 million. The working interests acquired consist primarily of unproved properties. The Piceance acreage was purchased for $75 million, which is being paid in three annual installments. The first installment of $25 million was paid on May 3, 2007. Additional 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, with the first interest payment made on July 1, 2007. Interest accrues at a LIBOR rate plus a margin. The interest rate was 5.66% at June 30, 2007.

Balance Sheet and Statement of Operations Information

Other balance sheet and statement of operations information is as follows:

	June 30, 2007 (in thousands)	December 31, 2006
Other Current Assets		
Derivative instruments	$ 13,303	$ 35,242
Materials and supplies inventories	52,415	46,973
Prepaid expenses and other current assets	75,713	44,973
Total	$ 141,431	$ 127,188
Other Noncurrent Assets		
Equity method investments	$ 371,759	$ 373,372
Mutual fund investments	125,826	116,314
Probable insurance claims	43,636	46,500
Derivative instruments	487	2,862
Other noncurrent assets	32,613	28,984
Total	$ 574,321	$ 568,032
Other Current Liabilities		
Accrued and other current liabilities	$ 150,045	$ 219,885
Interest payable	16,536	15,507
Total	$ 166,581	$ 235,392
Other Noncurrent Liabilities		
Deferred compensation liability	$ 199,897	$ 173,253
Accrued benefit costs	65,304	58,491
Other noncurrent liabilities	76,847	42,976
Total	$ 342,048	$ 274,720

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007 (in thousands)	2006	2007	2006
Other Revenues				
Electricity sales	$ 13,905	$ 15,519	$ 37,129	$ 33,431
Gathering, marketing and processing	4,420	6,760	11,136	14,943
Total	$ 18,325	$ 22,279	$ 48,265	$ 48,374
Other Expense, net				
Electricity generation (1)	$ 12,169	$ 14,597	$ 28,262	$ 25,224
Gathering, marketing and processing	3,977	5,968	8,993	11,470
Deferred compensation expense	3,017	5,563	14,666	14,740
Impairment of operating assets		6,359		6,359
Other	1,585	(4,098)	(3,215)	(2,681)
Total	$ 20,748	$ 28,389	$ 48,706	$ 55,112

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(1) Includes increases in the allowance for doubtful accounts of $2 million and $3 million for second quarter 2007 and 2006, respectively, and $7 million and $4 million for the first six months of 2007 and 2006, respectively. We increased the allowance to cover potentially uncollectible balances related to our Ecuador power operations. Certain entities purchasing electricity in Ecuador have been slow to pay amounts due us. We are pursuing various strategies to protect our interests including international arbitration and litigation.

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 fixed to variable 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 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.

Effects of cash flow hedges on gains and losses on derivative instruments were as follows:

	Three Months Ended June 30, 2007 (in thousands)	2006	Six Months Ended June 30, 2007	2006
Reclassified from AOCL	$	$ 398,517	$	$ 423,910
Mark-to-market gain on derivative instruments not accounted for as cash flow hedges				(39,212)
Ineffectiveness (gains) losses	(1,066)	2,680	(2,071)	11,341
(Gain) loss on derivative instruments	$ (1,066)	$ 401,197	$ (2,071)	$ 396,039

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

	Three Months Ended June 30, 2007 (in thousands)	2006	Six Months Ended June 30, 2007	2006
Increase (decrease) in natural gas sales	$ 29,245	$ (10,734)	$ 72,084	$ (61,936)
Decrease in crude oil sales	(39,959)	(57,186)	(68,062)	(113,301)
Total (decrease) increase in oil and gas sales	$ (10,714)	$ (67,920)	$ 4,022	$ (175,237)

The increase in natural gas sales in 2007 includes 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 six months of 2007. These non-cash increases totaled $40 million for second quarter 2007 and $91 million for the first six months of 2007.

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At June 30, 2007, we had entered into fixed to variable price swap derivative instruments related to natural gas and crude oil sales as follows:

	Natural Gas		Crude Oil	
Production Period	MMBtupd	Average price per MMBtu	Bopd	Average Price per Bbl
July - December 2007 (NYMEX)	170,000	$ 5.83	17,100	$ 38.89
2008 (NYMEX)	170,000	5.66	16,500	38.23

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

	Natural Gas	
Production Period	MMBtupd	Average Differential per MMBtu
July - December 2007 (CIG (1)vs. NYMEX)	100,000	$ 2.02
July - December 2007 (ANR (2) vs. NYMEX)	30,000	1.17
July - 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

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(1) Colorado Interstate Gas - North System

(2) ANR Oklahoma Pipeline

(3) Panhandle Eastern Pipe Line

At June 30, 2007, we had entered into costless collar derivative instruments related to natural gas and crude oil sales as follows:

	Natural Gas			Crude Oil		
		Average price per MMBtu			Average price per Bbl	
Production Period	MMBtupd	Floor	Ceiling	Bopd	Floor	Ceiling
July - December 2007 (NYMEX)		$	$	2,700	$ 60.00	$ 74.30
July - December 2007 (CIG)	12,000	6.50	9.50			
July - December 2007 (Dated Brent)				6,516	45.00	70.55
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 June 30, 2007, approximately $70 million of deferred losses, net of taxes, related to the fair values of the derivative instruments included in AOCL at June 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 by December 2010.

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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 Employee Retirement Income Security Act of 1974. 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 (in thousands)	2006	2007	2006
Three Months Ended June 30,				
Service cost	$ 3,087	$ 2,701	$ 502	$ 528
Interest cost	2,474	2,240	293	321
Expected return on plan assets	(2,693)	(2,018)		
Transition obligation recognition	60	60		
Amortization of prior service cost	(129)	(45)	(232)	(184)
Recognized net actuarial loss	978	520	293	217
Net periodic benefit cost	$ 3,777	$ 3,458	$ 856	$ 882
Six Months Ended June 30,				
Service cost	$ 6,174	$ 6,006	$ 1,004	$ 1,272
Interest cost	4,948	4,512	586	690
Expected return on plan assets	(5,386)	(3,981)		
Transition obligation recognition	120	120		
Amortization of prior service cost	(258)	48	(464)	(243)
Recognized net actuarial loss	1,956	1,240	586	548
Net periodic benefit cost	$ 7,554	$ 7,945	$ 1,712	$ 2,267

Note 5 - Stock-Based Compensation

We recognized stock-based compensation expense as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007 (in thousands)	2006	2007	2006
Stock-based compensation expense	$6,631	$3,169	$12,078	$6,323
Tax benefit from expense recognized	2,493	1,109	4,541	2,213

During the six months ended June 30, 2007, we granted 1,478,836 stock options with a weighted-average grant-date fair value of $18.72 per option and awarded 533,002 shares of restricted stock subject to service conditions with a weighted-average grant-date fair value of $53.57 per share.

Note 6 - Effect of Gulf Coast Hurricanes

We have substantially completed our cleanup activities relating to the damage caused by Hurricane Ivan in 2004. During second quarter 2007, we completed the abandonment of the wells damaged by Ivan and in July 2007, we completed the lifting and removal of the three platform decks that were sheared from their supporting structures during the storm.

During the first half of 2007, several factors contributed to an increase in our estimated cleanup costs for Hurricane Ivan related damage. These factors include 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 expected project costs combined with net book value of the assets destroyed to reach approximately $300 million, which exceeded our maximum single event insurance coverage. As a result, we recorded $40 million as a loss on involuntary conversion for the first six months of 2007. As of June 30, 2007, we have been reimbursed $259 million by our insurance providers, our maximum single event insurance recovery at the time of the storm.

During second quarter 2007, we completed the abandonment of the wells damaged by Hurricane Katrina and in July 2007, we completed the lifting and removal of the platform deck that was sheared from its supporting structure during the storm.

The cost escalation problems that impacted the Hurricane Ivan cleanup activities also impacted the Hurricane Katrina cleanup activities, resulting in an increase in total cleanup costs. These increases caused the sum of the expected total cleanup and return to production costs to reach $130 million. As a result of these cost increases, we have recorded a loss on involuntary conversion of $10 million for the first six months of 2007. Our estimates for restoring a production platform and wells are approximately $70 million. The recovery of a significant portion of our insurance receivable is dependent upon the final redevelopment or settlement resolution with our insurance providers. As of June 30, 2007, we have been reimbursed $19 million by our insurance providers and have recorded probable insurance claims of $68 million.

Insurance reimbursements received to date have been for cleanup and return to production 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:

	Six Months Ended June 30, 2007 (in thousands)
Asset retirement obligations at beginning of period	$ 196,189
Liabilities incurred in current period	1,353
Liabilities settled in current period	(115,324)
Revisions	69,014
Accretion expense	4,428
Asset retirement obligations at end of period	$ 155,660

The ending aggregate amount includes $32 million related to damage to the Main Pass assets caused by Hurricanes Ivan and Katrina. 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 and summarized, 100% combined financial information are as follows:

	June 30, 2007 (in thousands)	December 31, 2006
Equity method investments:		
Atlantic Methanol Production Company, LLC (AMPCO, LLC)	$ 204,145	$ 211,325
Alba Plant LLC	150,663	146,051
Other	16,951	15,996
Total equity method investments	$ 371,759	$ 373,372

Summarized, 100% combined information:

	June 30, 2007 (in thousands)	December 31, 2006
Balance sheet information:		
Current assets	$ 230,119	$ 252,201
Noncurrent assets	846,715	857,465
Current liabilities	119,591	171,028
Noncurrent liabilities	2,249	2,385

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007 (in thousands)	2006	2007	2006
Statements of operations information:				
Operating revenues	$ 215,057	$ 174,265	$ 423,313	$ 354,862
Less cost of goods sold	49,895	49,850	104,297	90,743
Gross margin	165,162	124,415	319,016	264,119
Less other expense	9,780	10,792	20,489	26,661
Less income tax expense	4,472	8,283	18,632	16,839
Net income	$ 150,910	$ 105,340	$ 279,895	$ 220,619

Note 9 - Basic Earnings Per Share 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:

	Net Income 2007	Weighted Average Shares	Net Income 2006	Weighted Average Shares
	(in thousands, except per share amounts)			
Three Months Ended June 30:				
Net income available to common shareholders and weighted average shares outstanding	$ 209,105	170,900	$ (30,705)	177,160
Basic EPS	$ 1.22		$ (0.17)	
Net income available to common shareholders and weighted average shares outstanding	$ 209,105	170,900	$ (30,705)	177,160
Plus incremental shares from assumed conversions:				
Dilutive stock options		1,983		
Dilutive restricted stock		200		
Adjusted net income and shares	$ 209,105	173,083	$ (30,705)	177,160
Diluted EPS	$ 1.21		$ (0.17)	
Six Months Ended June 30:				
Net income available to common shareholders and weighted average shares outstanding	$ 420,917	170,873	$ 195,382	176,651
Basic EPS	$ 2.46		$ 1.11	
Net income available to common shareholders and weighted average shares outstanding	$ 420,917	170,873	$ 195,382	176,651
Plus incremental shares from assumed conversions:				
Dilutive stock options		2,021		3,662
Dilutive restricted stock		170		147
Adjusted net income and shares	$ 420,917	173,064	$ 195,382	180,460
Diluted EPS	$ 2.43		$ 1.08	

Certain stock options 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 2.8 million and 2.5 million weighted average shares for second quarter 2007 and 2006, respectively, and 2.6 million weighted average shares for both the first six months of 2007 and 2006.

Note 10 - Income Taxes

The income tax provision (benefit) consists of the following:

	Three Months Ended June 30, 2007	2006	Six Months Ended June 30, 2007	2006
	(in thousands)			
Current	$ 28,200	$ (5,758)	$ 72,520	$ 62,048
Deferred	55,796	(8,402)	103,516	47,059
Total income tax provision (benefit)	$ 83,996	$ (14,160)	$ 176,036	$ 109,107

Our effective tax rate decreased from 35.8% for the first six months of 2006 to 29.5% for the first six months of 2007. The decrease was due primarily to higher earnings from equity method investments in 2007, which is a favorable permanent

difference in calculating income tax expense. In addition, an increase in the valuation allowance on a deferred tax asset for future foreign tax credits increased income tax expense and resulted in an increase in the effective tax rate for 2006.

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 June 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: U.S. - 2003, Equatorial Guinea - 2004, China - 2003, Israel - 2000, UK - 2005 and the Netherlands - 2000. We recognize interest and penalties related to unrecognized tax benefits in income tax expense. We had accrued no interest or penalties at June 30, 2007, because the jurisdiction in which we have unrecognized tax benefits has not historically imposed interest and 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; 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 (in thousands)	North America	West Africa	North Sea	Israel	Other Int l Corporate & Marketing
Three Months Ended June 30, 2007						
Revenues from third parties	$ 745,243	$ 414,952	$ 121,531	$ 62,169	$ 23,936	$ 122,655
Intersegment revenue		71,364				(71,364)
Income from equity method investees	48,970		48,970			
Total Revenues	794,213	486,316	170,501	62,169	23,936	51,291
Depreciation, depletion and amortization	181,227	146,466	6,773	15,453	4,122	8,413
Gain on derivative instruments	(1,066)	(1,066)				
Loss on involuntary conversion	38,291	38,291				
Income (loss) before taxes	293,101	159,984	142,356	27,360	17,493	(54,092)
Three Months Ended June 30, 2006						
Revenues from third parties	$ 737,139	$ 412,226	$ 97,333	$ 26,354	$ 18,231	$ 182,995
Intersegment revenue		121,064				(121,064)
Income from equity method investees	35,441		35,441			
Total Revenues	772,580	533,290	132,774	26,354	18,231	61,931
Depreciation, depletion and amortization	168,648	151,331	4,206	1,456	3,053	8,602
Loss on derivative instruments	401,197	401,197				
Income (loss) before taxes	(44,865)	(152,136)	118,391	17,881	13,338	(42,339)

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	Consolidated (in thousands)	North America	West Africa	North Sea	Israel	Other Int l Corporate & Marketing
Six Months Ended June 30, 2007						
Revenues from third parties	$ 1,442,225	$ 812,612	$ 185,268	$ 117,330	$ 49,311	$ 277,704
Intersegment revenue		166,940				(166,940)
Income from equity method investees	94,533		94,533			
Total Revenues	1,536,758	979,552	279,801	117,330	49,311	110,764
Depreciation, depletion and amortization	345,187	284,287	10,015	27,108	7,833	15,944
Gain on derivative instruments	(2,071)	(2,071)				
Loss on involuntary conversion	51,406	51,406				
Income (loss) before taxes	596,953	377,492	225,802	59,521	37,175	(103,037)
Six Months Ended June 30, 2006						
Revenues from third parties	$ 1,409,486	$ 691,039	$ 221,372	$ 62,641	$ 37,990	$ 396,444
Intersegment revenue		273,107				(273,107)
Income from equity method investees	75,091		75,091			
Total Revenues	1,484,577	964,146	296,463	62,641	37,990	123,337
Depreciation, depletion and amortization	293,113	256,023	10,321	3,330	6,252	17,187
Loss on derivative instruments	396,039	396,039				
Income (loss) before taxes	304,489	49,223	266,283	43,544	28,066	(82,627)
Total assets at June 30, 2007 (1)	$ 9,989,060	$ 7,388,717	$ 1,133,469	$ 391,320	$ 268,890	$ 806,664
Total assets at December 31, 2006 (1)	9,588,625	7,224,920	960,357	343,236	256,913	803,199

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(1) North America includes goodwill of $767 million and $781 million at June 30, 2007 and December 31, 2006, respectively.

Note 12 - Commitments and Contingencies

Legal Proceedings In January 2003, Patina Oil & Gas Corporation (Patina), a company acquired by us in 2005, was named as a defendant in a lawsuit alleging that Patina had improperly deducted certain costs in connection with its calculation of royalty payments relating to its Wattenberg field operations *(Jack Holman, et al v. Patina Oil & Gas Corporation; Case No. 03-CV-09; District Court, Weld County, Colorado).* In October 2006, we received service in an additional lawsuit styled *Wardell Family Partnership and Glen Droegemueller v. Noble Energy, Inc. et al; Case No. 06-CV-734, District Court, Weld County, Colorado,* involving royalty and overriding royalty interest owners in the same field and not members of the *Holman* class. Through a mediation process, we and the attorneys representing the *Holman* class and *Wardell* putative class entered into a Settlement Agreement dated February 15, 2007. Such a settlement was preliminarily approved by the court with notice of the settlement published in local newspapers and sent to all members of the *Holman* class and *Wardell* putative class. In accordance with the terms of the Settlement Agreement, we deposited the settlement funds into an escrow account in April 2007. At a Final Approval Hearing on June 11, 2007, the Court approved the settlement. The amount of the settlement was fully accrued and had no material

adverse effect on our financial position, results of operations or cash flows.

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 subsidiaries, Elysium Energy, LLC and Noble Energy Production, Inc. On March 16, 2007, the IEPA accepted Noble Energy Production s and Elysium s compliance commitment agreement wherein the

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companies 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. However, the matter will remain open until the emissions control system is constructed and operating within IEPA parameters and the SEP is completed, which is expected to occur in the third quarter of 2007.

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.

	Six Months Ended June 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	81,961
Reclassified to proved oil and gas properties based on determination of proved reserves	(6,062)
Capitalized exploratory well costs charged to expense	(2,835)
Capitalized exploratory well costs at end of period	$ 153,423

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:

	June 30, 2007 (in thousands)	**December 31, 2006**
Capitalized exploratory well costs that have been capitalized for a period of one year or less	$ 129,374	$ 58,493
Capitalized exploratory well costs that have been capitalized for a period greater than one year after completion of drilling	24,049	21,866
Balance at end of period	$ 153,423	$ 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	5	4

Capitalized exploratory well costs capitalized for more than one year at June 30, 2007 included five 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 remaining four projects, which total approximately $3 million, are all located in Alabama and are currently waiting on product sales lines.

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 will 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.

Second quarter 2007 financial results included the following:

- net income of $209 million and diluted earnings per share of $1.21, as compared with a net loss of $31 million and diluted loss per share of $0.17 for second quarter 2006;
- cash flow from operating activities of $351 million, as compared with $407 million for second quarter 2006; and
- increase in dividends paid to 12.0 cents per common share during second quarter 2007.

Second quarter 2007 operational results included the following:

- acquisition of approximately 280,000 net acres onshore North America in the Piceance, Niobrara and New Albany Shale areas;
- deepwater Gulf of Mexico exploration success at Isabela (Mississippi Canyon Block 562);
- successful exploration well (Benita) in Block I, offshore Equatorial Guinea;
- sales of natural gas to a liquefied natural gas (LNG) plant in Equatorial Guinea;
- substantial completion of hurricane cleanup activities at Main Pass in the Gulf of Mexico;
- 15% decrease in domestic sales volumes as compared with second quarter 2006 due primarily to the loss of production from Gulf of Mexico shelf properties sold in July 2006; and
- 50% increase in consolidated international sales volumes as compared with second quarter 2006.

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 in western Colorado where we are continuing an active drilling program;

- a full year of production from our acquisition of U.S. Exploration; and
- partially offset by loss of production from Gulf of Mexico shelf properties sold in July 2006 and natural production decline in certain fields.

Factors impacting our expected production profile for 2007 include:

- seasonal rainfall variations in Ecuador that affect our natural gas-to-power project;
- 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 North America operations; 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 $1.6 billion compared to the $1.42 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, and increases in our deepwater Gulf of Mexico and West Africa programs. The increase in deepwater is primarily associated with the recent Isabela discovery. Capital additions in West Africa are due to the addition of a second drilling rig which is now operating in Cameroon. Approximately 28% of the 2007 capital expenditures will be spent for exploration opportunities and 72% will be spent for production, development and other projects. On a geographic basis, approximately 77% of the capital expenditures will be domestic spending, 21% will be international spending and 2% 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. We are continuing our assessment of the impact of the change in the law and 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 properties may also generate funds. We had $302 million in cash and cash equivalents at June 30, 2007, compared with $153 million at December 31, 2006. The increase was provided by an excess of cash flows from operating activities ($773 million) and financing activities ($71 million), over cash flows used for additions to property, plant and equipment ($695 million).

Cash Flows

Operating Activities For the first six months of 2007, we reported net cash provided by operating activities of $773 million as compared with $934 million for the first six months of 2006. Significant factors contributing to the decrease in net cash provided by operating activities included:

- decrease in other current liabilities primarily the result of timing of cash disbursements;
- increase in exploration costs, general and administrative expense and transportation costs; and
- offset by dividends from equity method investees, which had been classified as investing cash flows in 2006 (See Item 2. Results of Operations Equity Method Investees).

Investing Activities Net cash used in investing activities for the first six months of 2007 totaled $695 million, as compared with $949 million for the first six months of 2006. Investing activities for 2007 to date are related to capital expenditures, including lease acquisitions of unproved crude oil and natural gas properties. Significant investing activities for the first six months of 2006 included:

- $412 million used for our acquisition of U.S. Exploration;
- $630 million used for capital expenditures;
- offset by $78 million in distributions received from equity method investees (See Item 2. Results of Operations Equity Method Investees); and
- $17 million proceeds from property sales.

Financing Activities Net cash provided by financing activities for the first six months of 2007 totaled $71 million, as compared with $86 million for the first six months of 2006. Significant financing activities for the first six months of 2007 included:

- $165 million net proceeds from long-term borrowings;
- $15 million net proceeds from short-term borrowings; and
- offset by $102 million used for repurchases of our common stock.

Significant financing activities for the first six months of 2006 included $95 million net proceeds from short-term and long-term borrowings.

Acquisition, Capital and Other Exploration Expenditures

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

	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2007	**2006**	**2007**	**2006**
	(in thousands)			
Acquisition, Capital and Other Exploration Expenditures				
Lease acquisition of unproved property	$ 103,385	$ 114,205	$ 106,787	$ 130,819
Lease acquisition of proved property	5,587	412,687	5,587	412,687
Exploration expenditures	90,979	104,391	152,566	141,077
Development expenditures	271,182	281,346	481,685	497,263
Corporate and other expenditures	9,997	3,356	18,815	10,082
Total	$ 481,130	$ 915,985	$ 765,440	$ 1,191,928

Insurance Recoveries

We have substantially completed our cleanup activities relating to the damage caused by Hurricanes Ivan in 2004 and Katrina in 2005. During second quarter 2007, we completed the abandonment of the wells damaged by Hurricanes Ivan and Katrina and in July 2007, we completed the lifting and removal of platform decks that were sheared from their supporting structures during the storm. During the first half of 2007, several factors contributed to an increase in our cleanup cost estimate for damage caused by Hurricanes Ivan and Katrina. These factors include cost escalation due to weather delays, 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 expected total project costs to exceed our estimated recoverable insurance coverage and we have recorded a $51 million loss on involuntary conversion for the first half of 2007.

We expect to spend approximately $32 million on hurricane-related asset retirement obligations in the third quarter 2007, which we have fully accrued. Insurance recovery related to additional increases in our asset retirement obligations or redevelopment costs will be limited by our maximum coverage per loss event or the insurance providers aggregation limit per event.

Our corporate insurance program provides up to $260 million property damage coverage per loss event. Our insurance carrier determined that its aggregation limit for catastrophic windstorm events would be increased from $500 million to $750 million effective June 1, 2007. While the increase is to our benefit, if an insured catastrophic loss event occurs, we could still recover less than our stated limits should the total aggregate losses realized by our carrier exceed its $750 million aggregation limit applicable to any single loss event.

We carry additional property damage and control of well coverage for our deepwater and remaining Gulf of Mexico shelf assets. This additional insurance provides coverage only for claims in excess of $100 million, which exceed the $260 million property damage coverage or where the $260 million property damage coverage is reduced by application of the $750 million aggregation limit. Effective June 2007, we no longer carry business interruption insurance for our Gulf of Mexico deepwater operations.

Financing Activities

Long-Term Debt Our long-term debt totaled $1.995 billion (excluding unamortized discount) at June 30, 2007. Maturities range from 2009 to 2097. Our ratio of debt-to-book capital was 32% at June 30, 2007 as compared with 30% at December 31, 2006. We define our ratio of debt-to-book capital as total debt (including both current and long-term portions and excluding unamortized discount) 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 June 30, 2007, $1.32 billion in borrowings were outstanding under the Credit Facility. The weighted average interest rate applicable to borrowings under the Credit Facility at June 30, 2007 was 5.67%.

We also have $650 million of fixed-rate debt outstanding at June 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, with the first interest payment made on July 1, 2007. Interest accrues at a LIBOR rate plus a margin. The interest rate was 5.66% at June 30, 2007.

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. At June 30, 2007, we had $15 million of short-term borrowings outstanding under uncommitted lines with an interest rate of 5.48%.

Dividends We paid quarterly cash dividends of 19.5 cents per share of common stock during the first six months of 2007 and 12.5 cents per share of common stock during the first six months of 2006. On July 24, 2007, our Board of Directors declared a quarterly cash dividend of 12 cents per common share, payable August 20, 2007 to shareholders of record on August 6, 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 $16 million from the exercise of stock options during the first six months of 2007 as compared to $29 million during the first six months of 2006.

RESULTS OF OPERATIONS

Natural Gas Information

Natural gas sales decreased 1% during second quarter 2007 as compared with second quarter 2006 due to a 4% decline in average realized sales prices offset by a 3% increase in sales volumes. Natural gas sales increased 2% for the first six months of 2007 as compared with 2006 due to a 3% increase in average realized sales prices, offset by a 1% decline in sales volumes. Natural gas sales were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(in thousands)			
Natural gas sales	$ 305,107	$ 307,651	$ 639,003	$ 626,828

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 six months of 2007. These non-cash increases totaled $40 million for second quarter 2007 and $91 million for the first six months of 2007.

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

	2007 Mcfpd	$/Mcf	2006 Mcfpd	$/Mcf
Three Months Ended June 30,				
North America (1)	417,779	$ 7.25	493,268	$ 6.29
West Africa (2)	115,922	0.29	37,741	0.41
North Sea	5,254	4.81	8,342	7.19
Israel	97,487	2.70	75,317	2.66
Ecuador (3)	21,655		21,908	
Other International	39	1.00	360	1.15
Total	658,136	$ 5.27	636,936	$ 5.50
Six Months Ended June 30,				
North America (1)	413,053	$ 7.74	477,993	$ 6.61
West Africa (2)	85,773	0.31	46,130	0.38
North Sea	6,207	5.51	8,413	8.91
Israel	100,285	2.72	78,916	2.66
Ecuador (3)	25,940		24,102	
Other International	39	1.00	388	1.12
Total	631,297	$ 5.83	635,942	$ 5.66

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(1) Average realized sales prices include the effects of hedging activities. Hedging activities resulted in increases (reductions) per Mcf of $0.77 and $(0.24) for second quarter 2007 and 2006, respectively, and $0.96 and $(0.72) for the first six 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) 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 $37 million and $33 million are included in other revenues for the first six months of 2007 and 2006, respectively.

Factors contributing to the change in natural gas sales volumes for the second quarter and first six months of 2007 as compared with 2006 included:

- reduction due to sale of Gulf of Mexico shelf properties in 2006; and

- a temporary decline in production due to third party processing downtime and inclement weather in the Northern region of our North America operations.

offset by:

- sales of natural gas to an LNG facility in Equatorial Guinea;

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

- a full six months of sales to Israeli Electric Company s Reading power plant in Tel Aviv.

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Crude Oil Information

Crude oil sales increased 4% for second quarter 2007 as compared with second quarter 2006 due to a 3% increase in total consolidated sales volumes and a 1% increase in average realized sales prices. Crude oil sales increased 3% for the first six months of 2007 as compared with 2006 due to a 3% increase in total consolidated sales volumes. Crude oil sales were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(in thousands)			
Crude oil sales	$ 421,811	$ 407,209	$ 754,957	$ 734,284

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 Production (3) Bopd	Sales Bopd	$/Bbl	2006 Production (3) Bopd	Sales Bopd	$/Bbl
Three Months Ended June 30,						
North America (1)	45,068	45,068	$ 51.34	51,983	51,983	$ 53.01
West Africa	16,054	18,799	69.23	18,046	15,332	68.76
North Sea	10,744	9,692	67.88	3,811	3,322	69.14
Other International	7,161	7,172	50.51	7,200	7,777	55.98
Total Consolidated Operations	79,027	80,731	57.42	81,040	78,414	57.07
Equity Investees (2)	8,500	9,096	50.60	7,552	7,439	46.68
Total	87,527	89,827	$ 56.73	88,592	85,853	$ 56.19
Six Months Ended June 30,						
North America (1)	45,321	45,321	$ 48.88	44,634	44,634	$ 48.53
West Africa	16,152	15,536	64.15	18,027	19,267	62.58
North Sea	10,038	9,528	64.45	3,993	3,786	71.62
Other International	7,253	7,212	47.87	7,295	7,788	53.12
Total Consolidated Operations	78,764	77,597	53.75	73,949	75,475	53.75
Equity Investees (2)	8,357	8,061	47.96	7,253	7,780	45.85
Total	87,121	85,658	$ 53.21	81,202	83,255	$ 53.02

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(1) Hedging activities resulted in reductions per Bbl of $9.74 and $12.09 for second quarter 2007 and 2006, respectively, and $8.30 and $14.02 for the first six months of 2007 and 2006, respectively.

(2) Volumes represent sales of condensate and LPG from the Alba plant in Equatorial Guinea. LPG volumes were 7,009 Bpd and 5,217 Bpd for second quarter 2007 and 2006, respectively, and 6,099 Bopd and 6,131 Bopd for the first six months of 2007 and 2006, respectively.

(3) The variance between production and sales volumes is attributable to the timing of liquid hydrocarbon tanker liftings.

Factors contributing to the change in crude oil sales volumes for the second quarter and first six months of 2007 as compared with 2006 included:

- contribution of Dumbarton North Sea development;

- a full six 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 of Gulf of Mexico shelf properties in 2006;
- timing of liftings in Equatorial Guinea; and

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- temporary decline in production due to inclement weather in the Northern region.

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 $11 million and $68 million for second quarter 2007 and 2006, respectively. Oil and gas sales were increased by $4 million for the first six months of 2007 and decreased by $175 million for the first six months of 2006. 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 June 30,		Six Months Ended June 30,	
	2007	**2006**	**2007**	**2006**
Net income (in thousands):				
AMPCO, LLC and affiliates	$ 11,002	$ 11,566	$ 35,755	$ 24,113
Alba Plant LLC	$ 37,968	$ 23,875	$ 58,778	$ 50,978
Distributions/Dividends (in thousands):				
AMPCO, LLC	$ 21,445	$ 9,750	$ 42,408	$ 19,500
Alba Plant LLC	$ 22,806	$ 29,747	$ 54,536	$ 76,020
Sales volumes:				
Methanol (Kgal)	33,559	32,355	73,251	66,464
Condensate (Bopd)	2,087	2,222	1,962	1,649
LPG (Bpd)	7,009	5,217	6,099	6,131
Production volumes:				
Condensate (Bopd)	1,956	1,792	1,937	1,682
LPG (Bpd)	6,544	5,760	6,420	5,571
Average realized prices:				
Methanol (per gallon)	$ 0.87	$ 0.84	$ 1.06	$ 0.83
Condensate (per Bbl)	$ 70.76	$ 68.86	$ 65.46	$ 66.32
LPG (per Bbl)	$ 44.60	$ 37.24	$ 42.34	$ 40.34

For the first six months of 2007, net income from AMPCO, LLC increased 48% relative to 2006 due to a 10% increase in methanol sales volumes and a 28% increase in average realized methanol prices.

For second quarter 2007, net income from Alba Plant LLC increased 59% relative to 2006 due to a 34% increase in LPG sales volumes and a 20% increase in average realized LPG prices. For the first six months of 2007, net income from Alba Plant LLC increased 15% relative to 2006 due to a 19% increase in condensate sales volumes.

For the first six months of 2007, the $55 million received from Alba Plant LLC was classified within operating cash flows as a dividend from equity method investee as compared to the first six 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 LLC in December 2006.

Costs and Expenses

Production Costs Production costs were as follows:

	Consolidated (in thousands)	North America	West Africa	North Sea	Israel	Other Int l / Corporate(2)
Three Months Ended June 30, 2007						
Oil and gas operating costs (1)	$ 76,469	$ 50,808	$ 10,840	$ 7,197	$ 2,145	$ 5,479
Workover and repair expense	6,094	6,038				56
Lease operating expense	82,563	56,846	10,840	7,197	2,145	5,535
Production and ad valorem taxes	28,748	24,077				4,671
Transportation costs	16,052	13,978		1,758		316
Total production costs	$ 127,363	$ 94,901	$ 10,840	$ 8,955	$ 2,145	$ 10,522
Three Months Ended June 30, 2006						
Oil and gas operating costs (1)	$ 66,517	$ 50,406	$ 7,903	$ 2,310	$ 2,132	$ 3,766
Workover and repair expense	12,669	12,653				16
Lease operating expense	79,186	63,059	7,903	2,310	2,132	3,782
Production and ad valorem taxes	27,513	21,660				5,853
Transportation costs	8,871	7,289		1,398		184
Total production costs	$ 115,570	$ 92,008	$ 7,903	$ 3,708	$ 2,132	$ 9,819

	Consolidated (in thousands)	North America	West Africa	North Sea	Israel	Other Int l / Corporate(2)
Six Months Ended June 30, 2007						
Oil and gas operating costs (1)	$ 151,389	$ 105,973	$ 17,531	$ 13,257	$ 4,281	$ 10,347
Workover and repair expense	10,049	9,867				182
Lease operating expense	161,438	115,840	17,531	13,257	4,281	10,529
Production and ad valorem taxes	53,915	44,544				9,371
Transportation costs	27,086	21,776		4,232		1,078
Total production costs	$ 242,439	$ 182,160	$ 17,531	$ 17,489	$ 4,281	$ 20,978
Six Months Ended June 30, 2006						
Oil and gas operating costs (1)	$ 129,119	$ 96,604	$ 15,450	$ 4,643	$ 4,255	$ 8,167
Workover and repair expense	32,260	32,175				85
Lease operating expense	161,379	128,779	15,450	4,643	4,255	8,252
Production and ad valorem taxes	52,966	43,737				9,229
Transportation costs	13,932	10,664		2,891		377
Total production costs	$ 228,277	$ 183,180	$ 15,450	$ 7,534	$ 4,255	$ 17,858

(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 $10 million, or 15%, second quarter 2007, as compared with second quarter 2006, and increased $22 million, or 17%, for the first six months of 2007, as compared with the first six months of 2006. The increases are primarily the result of expanded operations in the deepwater Gulf of Mexico, the Northern region of our North America operations, and the North Sea. In addition, the first six months of 2007 includes increased expense, including snow removal cost, related to severe winter weather in the Northern region.

Workover and repair expense decreased $7 million for second quarter 2007 and decreased $22 million for the first six months of 2007, as compared with 2006. Hurricane-related repair expense was $1 million for the first six months of 2007, as

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compared with $7 million for second quarter 2006 and $21 million for the first six months of 2006. In addition, workover activity was reduced due to severe winter weather in the Northern region of our North America operations during first quarter 2007.

Transportation costs increased second quarter 2007 and the first six months of 2007, as compared with 2006, primarily due to increased activity in the Niobrara Trend area and 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 June 30,		**Six Months Ended June 30,**	
	2007	**2006**	**2007**	**2006**
Oil and gas operating costs	$ 4.41	$ 3.97	$ 4.58	$ 3.93
Workover and repair expense	0.35	0.75	0.30	0.98
Lease operating expense	4.76	4.72	4.88	4.91
Production and ad valorem taxes	1.66	1.64	1.63	1.61
Transportation costs	0.93	0.53	0.82	0.42
Total production costs (1)	$ 7.35	$ 6.89	$ 7.33	$ 6.94

(1) Consolidated unit rates exclude sales volumes and costs attributable to equity method investees and were positively impacted by $0.40 per BOE and $0.21 per BOE for the three and six months ending June 30, 2007, respectively, due to natural gas sales to the Equatorial Guinea LNG plant that began late first quarter of 2007.

The unit rate of total production costs per BOE increased second quarter 2007 and the first six months of 2007 as compared with 2006. Contributing to the increase is the impact of the mix of our sales volumes on the unit rate of oil and gas operations cost. 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 $54 million for second quarter 2007, as compared with $29 million for second quarter 2006. The increase was due to a $20 million increase in seismic expenditures for the Gulf of Mexico and North Sea and a $3 million increase in dry hole expense. Oil and gas exploration expense was $99 million for the first six months of 2007, as compared with $61 million for the first six months of 2006. The increases were due to a $17 million increase in seismic expenditures for the Gulf of Mexico and North Sea, a $16 million increase in dry hole expense, and increased staff expense related to new venture activity.

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

	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2007	**2006**	**2007**	**2006**
DD&A expense (in thousands)	$ 181,227	$ 168,648	$ 345,187	$ 293,113
Unit rate per BOE sales volume (1)	10.46	10.04	10.43	8.92

(1) Consolidated unit rates exclude sales volumes and costs attributable to equity method investees and were positively impacted by $0.46 per BOE and $0.24 per BOE for the three and six months ending June 30, 2007, respectively, due to natural gas sales to the Equatorial Guinea LNG plant that began late first quarter of 2007.

Total DD&A expense for second quarter and the first six months of 2007 increased as compared to 2006 due to both higher sales volumes and higher rates. The increase in the expense and unit rate was primarily due to additional sales volumes and 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 June 30, 2007	2006	Six Months Ended June 30, 2007	2006
G&A expense (in thousands)	$ 47,761	$ 37,661	$ 92,850	$ 73,059
Unit rate per BOE sales volume (1)	2.76	2.24	2.81	2.22

(1) Consolidated unit rates exclude sales volumes and costs attributable to equity method investees and were positively impacted by $0.14 per BOE and $0.07 per BOE for the three and six months ending June 30, 2007, respectively, due to natural gas sales to the Equatorial Guinea LNG plant that began late first quarter of 2007.

G&A expense for second quarter and the first six months of 2007 increased as compared to 2006 primarily due to higher salaries and wages resulting from an increase in employees to address our increase in activities. G&A expense includes stock-based compensation expense of $7 million and $3 million for second quarter 2007 and 2006, respectively, and $12 million and $6 million for the first six months of 2007 and 2006, respectively.

Interest Expense and Capitalized Interest For second quarter 2007, interest expense, net of interest capitalized, decreased to $31 million, from $34 million for second quarter 2006. For the first six months of 2007, interest expense, net of interest capitalized, decreased to $58 million, from $67 million for the first six months of 2006. Capitalized interest was $3 million and $1 million for second quarter 2007 and 2006, respectively, and $6 million and $2 million for the first six months of 2007 and 2006, respectively. Interest expense, net of interest capitalized, decreased in 2007 primarily due to a lower average outstanding debt balance.

Loss on Derivative Instruments See Item I. Financial Statements Note 3 Derivative Instruments and Hedging Activities.

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

Income Tax Provision The income tax provision (benefit) was as follows:

	Three Months Ended June 30, 2007	2006	Six Months Ended June 30, 2007	2006
Income tax provision (benefit) (in thousands)	$ 83,996	$ (14,160)	$ 176,036	$ 109,107
Effective rate	28.7 %	31.6 %	29.5 %	35.8 %

The decrease in the effective rate was due primarily to higher earnings from equity method investments for the first six months of 2007, which is a favorable permanent difference in calculating income tax expense. In addition, an increase in the valuation allowance on a deferred tax asset for future foreign tax credits increased income tax expense and resulted in an increase in the effective rate in 2006.

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 June 30, 2007, we had entered into fixed to variable 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 June 30, 2007, we had a net unrealized loss of $254 million (pre-tax) related to crude oil and natural gas derivative instruments entered into for hedging purposes. A net unrealized loss of $158 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 June 30, 2007, we had $1.995 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 June 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 June 30, 2007, we had $1.345 billion of long-term variable-rate debt and $40 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 June 30, 2007 balance of variable-rate debt would result in a change in annual interest expense of approximately $8 million.

Foreign Currency Risk

We do not enter into foreign currency derivatives. The U.S. dollar is considered the functional currency for each of our international operations since substantially all sales transactions, operating expenses and capital expenditures in our foreign operations are denominated in U.S. dollars. Transactions that are completed in a foreign currency are remeasured into U.S. 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 and similar words, althoug
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 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

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

(a) Our annual stockholders meeting was held at 9:30 a.m., Central Time, on Tuesday, April 24, 2007 in Houston, Texas.

(b) Proxies were solicited by our Board of Directors pursuant to Regulation 14A under the Securities Exchange Act of 1934. There was no solicitation in opposition to the Board of Directors nominees as listed in the proxy statement and all such nominees were duly elected.

(c) Out of a total of 170,677,575 shares of our common stock outstanding and entitled to vote, 156,813,070 shares were present in person or by proxy, representing 91.9% of the outstanding shares of common stock.

The stockholder voting results are as follows:

Proposal I. Election of our Board of Directors to serve until the next annual stockholders meeting.

	Number of Shares Voting for Election As Director	**Number of Shares Withholding Authority To Vote for Election As Director**
Jeffrey L. Berenson	140,437,925	16,375,145
Michael A. Cawley	138,800,407	18,012,663
Edward F. Cox	139,323,087	17,489,983
Charles D. Davidson	138,839,126	17,973,944
Thomas J. Edelman	134,446,490	22,366,580
Kirby L. Hedrick	140,444,302	16,368,768
Bruce A. Smith	140,471,468	16,341,602
William T. Van Kleef	140,475,028	16,338,042

Proposal II. Ratification of appointment of KPMG LLP as our independent auditors.

(For 155,674,118; Against 1,070,950; Abstaining 68,002)

Proposal III. Approval of an amendment to the 1992 Stock Option and Restricted Stock Plan to increase the number of shares of common stock authorized for issuance under the plan from 18,500,000 to 22,000,000.

(For 99,520,879; Against 44,179,811; Abstaining 106,191; Broker Non-Votes 13,006,189)

Proposal IV. Stockholder proposal requiring that the Chairman of the Board be an independent director, with limited exceptions.

(For 34,833,067; Against 108,607,203; Abstaining 366,611; Broker Non-Votes 13,006,189)

ITEM 5. OTHER INFORMATION

None.

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 August 2, 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).