NOBLE ENERGY INC
Form 10-Q
October 20, 2011

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, 2011

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 (State or other jurisdiction of incorporation or organization)	73-0785597 (I.R.S. employer identification number)
100 Glenborough Drive, Suite 100 Houston, Texas (Address of principal executive offices)	77067 (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 has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes x No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of “large accelerated filer”, “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer x	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company 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

As of October 6, 2011, there were 176,645,583 shares of the registrant’s common stock, par value $3.33 1/3 per share, outstanding.

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Part I. Financial Information
Item 1. Financial Statements

Noble Energy, Inc.
Consolidated Statements of Operations

(millions, except per share amounts)
(unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Revenues				
Oil, Gas and NGL Sales	$874	$704	$2,599	$2,102
Income from Equity Method Investees	50	34	146	85
Other Revenues	-	17	33	52
Total	924	755	2,778	2,239
Costs and Expenses				
Production Expense	153	141	449	430
Exploration Expense	57	35	195	167
Depreciation, Depletion and Amortization	225	231	681	662
General and Administrative	89	65	254	194
Gain on Divestitures	-	(114)	(26)	(114)
Asset Impairments	-	100	139	100
Other Operating (Income) Expense, Net	2	4	45	59
Total	526	462	1,737	1,498
Operating Income	398	293	1,041	741
Other (Income) Expense				
Gain on Commodity Derivative Instruments	(322)	(38)	(179)	(280)
Interest, Net of Amount Capitalized	14	21	51	60
Other Non-Operating (Income) Expense, Net	(16)	12	(16)	(1)
Total	(324)	(5)	(144)	(221)
Income Before Income Taxes	722	298	1,185	962
Income Tax Provision	281	66	436	289
Net Income	$441	$232	$749	$673
Earnings Per Share, Basic	$2.50	$1.33	$4.25	$3.86
Earnings Per Share, Diluted	2.39	1.31	4.12	3.80
Weighted Average Number of Shares Outstanding, Basic	177	175	176	175
Weighted Average Number of Shares Outstanding, Diluted	180	177	179	178

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

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Noble Energy, Inc.
Consolidated Balance Sheets

(millions)
(unaudited)

	September 30, 2011	December 31, 2010
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 1,252	$ 1,081
Accounts Receivable, Net	546	556
Other Current Assets	279	201
Total Assets, Current	2,077	1,838
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method of Accounting)	17,180	14,393
Property, Plant and Equipment, Other	277	263
Total Property, Plant and Equipment, Gross	17,457	14,656
Accumulated Depreciation, Depletion and Amortization	(4,945)	(4,392)
Total Property, Plant and Equipment, Net	12,512	10,264
Goodwill	696	696
Other Noncurrent Assets	548	484
Total Assets	$ 15,833	$ 13,282
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable - Trade	$ 1,132	$ 927
Other Current Liabilities	826	495
Total Liabilities, Current	1,958	1,422
Long-Term Debt	3,507	2,272
Deferred Income Taxes, Noncurrent	2,235	2,110
Other Noncurrent Liabilities	551	630
Total Liabilities	8,251	6,434
Commitments and Contingencies		
Shareholders' Equity		
Preferred Stock - Par Value $1.00 per share; 4 Million Shares Authorized, None Issued	-	-
Common Stock - Par Value $3.33 1/3 per share; 250 Million Shares Authorized; 196 Million and 195 Million Shares Issued, Respectively	655	651
Additional Paid in Capital	2,467	2,385
Accumulated Other Comprehensive Loss	(85)	(104)
Treasury Stock, at Cost; 19 Million Shares	(640)	(624)
Retained Earnings	5,185	4,540
Total Shareholders' Equity	7,582	6,848
Total Liabilities and Shareholders' Equity	$ 15,833	$ 13,282

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

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Noble Energy, Inc.
Consolidated Statements of Cash Flows
(millions)
(unaudited)

	Nine Months Ended September 30,	
	2011	2010
Cash Flows From Operating Activities		
Net Income	$749	$673
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities		
Depreciation, Depletion and Amortization	681	662
Asset Impairments	139	100
Dry Hole Cost	57	57
Deferred Income Taxes	147	109
Dividends (Income) from Equity Method Investees, Net	23	6
Unrealized Gain on Commodity Derivative Instruments	(140)	(215)
Gain on Divestitures	(26)	(114)
Other Adjustments for Noncash Items Included in Income	52	40
Changes in Operating Assets and Liabilities		
(Increase) in Accounts Receivable	(7)	(63)
(Increase) Decrease in Other Current Assets	(17)	18
Increase in Accounts Payable	131	214
Increase in Current Income Taxes Payable	52	20
(Decrease) in Other Current Liabilities	(25)	(17)
Other Operating Assets and Liabilities, Net	(31)	(38)
Net Cash Provided by Operating Activities	1,785	1,452
Cash Flows From Investing Activities		
Additions to Property, Plant and Equipment	(1,868)	(1,326)
Marcellus Shale Asset Acquisition	(519)	-
Central DJ Basin Asset Acquisition	-	(458)
Additions to Equity Method Investments	(73)	-
Proceeds from Divestitures	77	552
Net Cash Used in Investing Activities	(2,383)	(1,232)
Cash Flows From Financing Activities		
Exercise of Stock Options	32	35
Excess Tax Benefits from Stock-Based Awards	11	19
Dividends Paid, Common Stock	(104)	(95)
Purchase of Treasury Stock	(16)	(12)
Proceeds from Credit Facilities	520	760
Repayment of Credit Facilities	(470)	(792)
Proceeds from Issuance of Senior Long-Term Debt, Net	836	-
Settlement of Interest Rate Derivative Instrument	(40)	-
Net Cash Provided By (Used In) Financing Activities	769	(85)
Increase in Cash and Cash Equivalents	171	135
Cash and Cash Equivalents at Beginning of Period	1,081	1,014
Cash and Cash Equivalents at End of Period	$1,252	$1,149

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

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Noble Energy, Inc.
Consolidated Statements of Shareholders' Equity
(millions)
(unaudited)

	Common Stock	Additional Paid in Capital	Acumulated Other Comprehensive Loss	Treasury Stock at Cost	Retained Earnings	Total Shareholders' Equity
December 31, 2010	$651	$2,385	$ (104)	$(624)	$4,540	$ 6,848
Net Income	-	-	-	-	749	749
Stock-based Compensation	-	43	-	-	-	43
Exercise of Stock Options	2	30	-	-	-	32
Tax Benefits Related to Exercise of Stock Options	-	11	-	-	-	11
Restricted Stock Awards, Net	2	(2)	-	-	-	-
Dividends (58 cents per share)	-	-	-	-	(104)	(104)
Changes in Treasury Stock, Net	-	-	-	(16)	-	(16)
Interest Rate Cash Flow Hedges						
Unrealized Change in Fair Value	-	-	15	-	-	15
Net Change in Other	-	-	4	-	-	4
September 30, 2011	$655	$2,467	$ (85)	$(640)	$5,185	$ 7,582
December 31, 2009	$645	$2,260	$ (75)	$(615)	$3,942	$ 6,157
Net Income	-	-	-	-	673	673
Stock-based Compensation	-	40	-	-	-	40
Exercise of Stock Options	3	32	-	-	-	35
Tax Benefits Related to Exercise of Stock Options	-	19	-	-	-	19
Restricted Stock Awards, Net	2	(2)	-	-	-	-
Dividends (54 cents per share)	-	-	-	-	(95)	(95)
Changes in Treasury Stock, Net	-	-	-	(12)	-	(12)
Oil and Gas Cash Flow Hedges						
Realized Amounts Reclassified Into Earnings	-	-	10	-	-	10
Interest Rate Cash Flow Hedges						
Unrealized Change in Fair Value	-	-	(92)	-	-	(92)
Net Change in Other	-	-	2	-	-	2
September 30, 2010	$650	$2,349	$ (155)	$(627)	$4,520	$ 6,737

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

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Noble Energy, Inc.

Notes to Consolidated Financial Statements
(unaudited)

Note 1. Organization and Nature of Operations

Noble Energy, Inc. (Noble Energy, we or us) is a leading independent energy company engaged in worldwide crude oil and natural gas exploration and production. Our key operating areas are onshore in the US, primarily in the DJ Basin and the Marcellus shale, in the deepwater Gulf of Mexico, offshore Eastern Mediterranean, and offshore West Africa.

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 (US GAAP) 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 GAAP for complete financial statements. The accompanying consolidated financial statements at September 30, 2011 and December 31, 2010 and for the three and nine months ended September 30, 2011 and 2010 contain all normally recurring adjustments considered necessary for a fair presentation of our financial position, results of operations, cash flows and shareholders' equity for such periods. Operating results for the three and nine months ended September 30, 2011 are not necessarily indicative of the results that may be expected for the year ending December 31, 2011. 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 accompanying notes included in our Annual Report on Form 10-K for the year ended December 31, 2010.

Consolidation Our consolidated accounts include our accounts and the accounts of our wholly-owned subsidiaries. In addition, we use the equity method of accounting for investments in entities that we do not control but over which we exert significant influence. All significant intercompany balances and transactions have been eliminated upon consolidation.

Estimates The preparation of consolidated financial statements in conformity with US 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.

Statements of Operations Information Other statements of operations information is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
(millions)				
Other Revenues				
Electricity Sales (1)	$ -	$ 19	$ 32	$ 53
Other	-	(2)	1	(1)
Total	$ -	$ 17	$ 33	$ 52
Production Expense				
Lease Operating Expense	$ 98	$ 95	$ 288	$ 283
Production and Ad Valorem Taxes	38	29	108	96

Transportation Expense		17		17		53		51
Total	$	153	$	141	$	449	$	430
Other Operating (Income) Expense, Net								
Deepwater Gulf of Mexico Moratorium Expense (2)	$	(1)	$	-	$	18	$	27
Electricity Generation Expense (1)		-		9		26		26
Loss on Involuntary Conversion (3)		-		-		4		-
Other, Net		3		(5)		(3)		6
Total	$	2	$	4	$	45	$	59
Other Non-Operating (Income) Expense, Net								
Deferred Compensation (Income) Expense (4)	$	(18)	$	15	$	(15)	$	4
Interest Income		(2)		(1)		(7)		(4)
Other (Income) Expense, Net		4		(2)		6		(1)
Total	$	(16)	$	12	$	(16)	$	(1)

(1) Electricity sales include sales from the Machala power plant located in Machala, Ecuador, through May 2011. Electricity generation expense includes all operating and non-operating expenses associated with the plant, including depreciation and changes in the allowance for doubtful accounts. See Note 3. Acquisitions and Divestitures.

(2) Amounts relate to rig stand-by expense incurred prior to receiving a permit to resume drilling activities in the deepwater Gulf of Mexico in 2011 and costs to terminate a deepwater Gulf of Mexico drilling rig contract due to the deepwater Gulf of Mexico drilling moratorium in 2010.

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Noble Energy, Inc.

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(unaudited)

(3) The loss on involuntary conversion represents our insurance deductible related to the Leviathan-2 appraisal well control incident. We suspended operations on the Leviathan-2 well, offshore Israel, in May 2011 when we identified water flowing to the sea floor from the wellbore. The incident was a covered event under our well control insurance. At this time, we expect to recover most of the costs from insurance, subject to a deductible. The final amount to be recovered will be based on the cost to drill the Leviathan-3 replacement well down to the same depth at which the incident occurred, possible remediation activities and/or abandonment activities at the Leviathan-2 well, which have not yet been determined, and other factors. See footnote (2) below.

(4) Amount represents increases (decreases) in the fair value of shares of our common stock held in a rabbi trust.

Balance Sheet Information   Other balance sheet information is as follows:

(millions)	September 30, 2011	December 31, 2010
Accounts Receivable, Net		
Commodity Sales	$ 228	$ 291
Joint Interest Billings	253	259
Other	73	33
Allowance for Doubtful Accounts (1)	(8)	(27)
Total	$ 546	$ 556
Other Current Assets		
Inventories, Current	$ 120	$ 112
Commodity Derivative Assets, Current	87	62
Deferred Income Taxes, Net, Current	15	8
Probable Insurance Claims (2)	25	-
Prepaid Expenses and Other Assets, Current	32	19
Total	$ 279	$ 201
Other Noncurrent Assets		
Equity Method Investments (3)	$ 339	$ 285
Mutual Fund Investments	101	112
Commodity Derivative Assets, Noncurrent	44	-
Other Assets, Noncurrent	64	87
Total	$ 548	$ 484
Other Current Liabilities		
Production and Ad Valorem Taxes	$ 128	$ 110
Commodity Derivative Liabilities, Current	6	24
Interest Rate Derivative Liability, Current	-	63
Income Taxes Payable	143	90
Asset Retirement Obligations, Current	45	45
Interest Payable	18	36
CONSOL Installment Payment (4)	322	-
Current Portion of FPSO Lease Obligation	33	-
Other	131	127
Total	$ 826	$ 495

Other Noncurrent Liabilities				
Deferred Compensation Liabilities, Noncurrent	$	210	$	229
Asset Retirement Obligations, Noncurrent		215		208
Accrued Benefit Costs, Noncurrent		63		76
Commodity Derivative Liabilities, Noncurrent		-		51
Other		63		66
Total	$	551	$	630

(1) The decrease in the allowance for doubtful accounts from December 31, 2010 is due primarily to the transfer of assets to the Ecuadorian government. See Note 3. Acquisitions and Divestitures.

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Noble Energy, Inc.

Notes to Consolidated Financial Statements
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(2) Amount represents the costs incurred to date of the Leviathan-2 appraisal well in excess of the insurance deductible. See footnote (3) above.

(3) The increase in equity method investments from December 31, 2010 is due to our acquisition of a 50% interest in CONE Gathering LLC. See Note 3. Acquisitions and Divestitures.

(4) See Note 3. Acquisitions and Divestitures and Note 5. Debt.

Recently Issued Accounting Standards Updates In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2011-04: Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs (ASU 2011-04). ASU 2011-04 clarifies application of fair value measurement and disclosure requirements and is effective for annual periods beginning after December 15, 2011. We are currently evaluating the provisions of ASU 2011-04 and assessing the impact, if any, it may have on our financial position and results of operations.

In June 2011, the FASB issued Accounting Standards Update No. 2011-05: Comprehensive Income (Topic 220): Presentation of Comprehensive Income (ASU 2011-05). ASU 2011-05 provides that an entity that reports items of other comprehensive income has the option to present comprehensive income in either one continuous financial statement or two consecutive financial statements. ASU 2011-05 is effective for annual periods beginning after December 15, 2011. We are currently evaluating the provisions of ASU 2011-05. We do not expect ASU 2011-05 to have any impact on our financial position and results of operations as it is a change in presentation only.

In September 2011, the FASB issued Accounting Standards Update No. 2011-08: Intangibles – Goodwill and Other (Topic 350): Testing Goodwill for Impairment (ASU 2011-08). ASU 2011-08 permits an entity to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test. The more-likely-than-not threshold is defined as having a likelihood of more than 50 percent. Under ASU 2011-08, an entity is not required to calculate the fair value of a reporting unit unless the entity determines that it is more likely than not that its fair value is less than its carrying amount. ASU 2011-08 is effective for annual periods beginning after December 15, 2011. We expect to adopt the provisions of ASU 2011-08 for our annual impairment test as of December 31, 2011. We do not expect ASU 2011-08 to have any impact on our financial position and results of operations as it is a change in application of the goodwill impairment test only.

Note 3. Acquisitions and Divestitures

Marcellus Shale Joint Venture Partnership On September 30, 2011, we closed an agreement with a subsidiary of CONSOL Energy Inc. (CONSOL) for the development of Marcellus shale properties in southwest Pennsylvania and northwest West Virginia. Under the agreement, we acquired 50% interests in 628,000 net undeveloped acres, existing Marcellus production, and existing infrastructure for approximately $1.2 billion. We and CONSOL formed CONE Gathering LLC, which we will account for using the equity method, to own and operate existing and future infrastructure.

We paid a total of $592 million in cash at the closing of the above transaction, funded with available cash and amounts drawn under our credit facility. In addition, we will make two additional installment payments of $328 million each, which will be paid September 30, 2012 and 2013.

In addition, we have agreed to fund one-third of CONSOL's 50% working interest share of future drilling and completion costs, up to approximately $2.1 billion (CONSOL Carried Cost Obligation). The CONSOL Carried Cost Obligation is expected to extend over an eight-year period. It is capped at $400 million in each calendar year and will be suspended if average Henry Hub natural gas prices fall and remain below $4.00 per MMBtu in any three consecutive month period and will remain suspended until average Henry Hub natural gas prices are above $4.00 per MMBtu for three consecutive months. Therefore, specific payment dates for the funding of the CONSOL Carried Cost Obligation cannot be determined at this time. Amounts paid pursuant to the CONSOL Carried Cost Obligation will be recorded as increases in property, plant and equipment in our consolidated balance sheets and as investing activities in our consolidated statements of cash flows.

As a result of the transaction, we recorded the following:

(millions)		September 30, 2011
Unproved Oil and Gas Properties	$	790
Proved Oil and Gas Properties		370
Investment in CONE Gathering LLC		73
Total Assets Acquired (1)	$	1,233

(1) Total reflects impact of discount on remaining installment payments. See Note 5. Debt.

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Noble Energy, Inc.

Notes to Consolidated Financial Statements
(unaudited)

To estimate the fair value of the proved oil and gas properties as of the acquisition date, we used an income approach. We utilized a discounted cash flow model which took into account the following inputs to arrive at estimates of future net cash flows:

- estimated quantities of crude oil and natural gas prepared by our qualified petroleum engineers;
- management's estimates of future commodity prices based on NYMEX Henry Hub natural gas futures prices and adjusted for estimated location and quality differentials;
- estimated future production rates based on our experience with similar properties which we operate; and
- estimated timing and amounts of future operating and development costs based on our experience with similar properties which we operate.

We discounted the resulting future net cash flows using a market-based weighted average cost of capital rate determined appropriate at the acquisition date. The fair value of the proved producing properties is considered a Level 3 fair value measurement.

Certain data necessary to complete the final purchase price allocation is not yet available, and includes, but is not limited to, final appraisals of assets acquired and liabilities assumed. We expect to complete the final purchase price allocation during the 12-month period following the acquisition date, during which time the preliminary allocation may be revised.

See Note 5. Debt and Note 7. Fair Value Measurements and Disclosures.

Gas Gathering Agreement with CONE Gathering LLC   On September 30, 2011, in connection with the Marcellus shale joint venture arrangement described above, we entered into a 50-year gathering and marketing agreement with CONE Gathering LLC. Under the terms of the gathering and marketing agreement, we will pay CONE Gathering LLC a minimum annual revenue commitment (MARC). The fee will be adjusted annually based on projected gathering volumes, operating expenses, capital expenditures, and other factors. We expect the MARC to total approximately $3 million in 2011 and $23 million in 2012. Amounts to be paid under the MARC for years beyond 2012 have not yet been determined.

We also have agreed to fund an annual work program for the construction of additional pipeline assets to receive and deliver production from future wells. Amounts to be contributed in future years to fund our proportionate share of the annual work program will be dependent upon anticipated production locations, volumes and other factors. We will account for our 50% interest in CONE Gathering LLC using the equity method; therefore, our share of income will be reported as income from equity method investees in our consolidated statements of operations. Our investment in CONE Gathering LLC will be reported as investment in equity method investee in our consolidated balance sheets and will reflect our cash contributions to the entity.

Divestitures In May 2011, we transferred our assets in Ecuador to the Ecuadorian government. We received cash proceeds of $73 million for the transfer of our offshore Amistad field assets and Block 3 production sharing contract (PSC), which was terminated by the government of Ecuador on November 25, 2010, and the assignment of the Machala Power Electricity concession and its associated assets. Our net book value for the assets had been reduced due to previous impairment charges, resulting in a gain of $26 million before tax. We did not consider the property disposition material for discontinued operations presentation.

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Noble Energy, Inc.
Notes to Consolidated Financial Statements
(unaudited)

In August 2010, we closed the sale of certain non-core assets in the Mid-Continent and Illinois Basin areas. Information regarding the sale is as follows:

(millions)	Nine Months Ended September 30, 2010
Cash Proceeds	$ 552
Less	
Net Book Value of Assets Sold	(394)
Goodwill Allocated to Assets Sold	(61)
Asset Retirement Obligations Associated with Assets Sold	10
Other Closing Adjustments	7
Gain on Asset Sale	$ 114

Note 4. Asset Impairments

Pre-tax (non-cash) asset impairment charges were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions)	2011	2010	2011	2010
East Texas (Onshore US)	$ -	$ -	$ 116	$ -
Iron Horse (Onshore US)	-	71	15	71
New Albany Shale (Onshore US)	-	19	-	19
Other	-	10	8	10
Total	$ -	$ 100	$ 139	$ 100

2011 Due to field performance combined with a low natural gas price environment, we determined that the carrying amounts of certain of our onshore US developments, primarily in East Texas, were not recoverable from future cash flows and, therefore, were impaired at June 30, 2011.

2010 Due to declines in natural gas prices and drilling results, we determined that the carrying amounts of our Iron Horse development and certain other US properties were not recoverable from future cash flows and, therefore, were impaired at September 30, 2010. We also recorded an impairment related to non-core, New Albany shale assets which were held-for-sale at September 30, 2010.

Assets to be held and used were written down to their estimated fair values, which were determined using discounted cash flow models. Assets held for sale were reduced to expected sales proceeds less costs to sell. See Note 7. Fair Value Measurements and Disclosures.

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Noble Energy, Inc.

Notes to Consolidated Financial Statements
(unaudited)

Note 5. Debt

Our debt consists of the following:

	September 30, 2011		December 31, 2010	
	Debt	Interest Rate	Debt	Interest Rate
(millions, except percentages)				
Credit Facility, due December 9, 2012	$ 400	0.56 %	$ 350	0.57 %
CONSOL Installment Payments, due September 30, 2012 and 2013	656	1.76 %	-	-
FPSO Lease Obligation	351	-	295	-
5¼% Senior Notes, due April 15, 2014	200	5.25 %	200	5.25 %
8¼% Senior Notes, due March 1, 2019	1,000	8.25 %	1,000	8.25 %
7¼% Notes, due October 15, 2023	100	7.25 %	100	7.25 %
8% Senior Notes, due April 1, 2027	250	8.00 %	250	8.00 %
6% Senior Notes, due March 1, 2041	850	6.00 %	-	-
7¼% Senior Debentures, due August 1, 2097	84	7.25 %	84	7.25 %
Total	3,891		2,279	
Unamortized Discount	(29)		(7)	
Total Debt, Net of Discount	3,862		2,272	
Less Amounts Due Within One Year				
CONSOL Installment Payment, due September 30, 2012, net of discount	(322)		-	
FPSO Lease Obligation	(33)		-	
Long-Term Debt Due After One Year	$ 3,507		$ 2,272	

CONSOL Installment Payments   On September 30, 2011, we closed an agreement with CONSOL for the development of Marcellus shale properties. In addition to the cash paid at closing, we agreed to make two installment payments of $328 million each on September 30, 2012 and 2013. The installment payments have been discounted at the prevailing market rates for similar debt instruments. The CONSOL installment loan is a non-cash financing activity. See Note 3. Acquisitions and Divestitures and Note 7. Fair Value Measurements and Disclosures.

FPSO Lease Obligation   We have entered into an agreement to lease a floating production, storage and offloading vessel (FPSO) to be used in the development of the Aseng field, offshore Equatorial Guinea. The amount of the FPSO lease obligation is based on the discounted present value of future minimum lease payments and the percentage of construction activities completed as of the reporting dates, and therefore does not reflect future minimum lease payments. The increase in the FPSO lease obligation is a non-cash financing activity. Amounts due within one year equal the amount by which the FPSO lease obligation is expected to be reduced during the next 12 months as lease payments begin. We currently expect production to commence, and lease payments to begin, by year end 2011.

Issuance of 6% Senior Notes   On February 18, 2011, we closed an offering of $850 million senior unsecured notes receiving net proceeds of $836 million, after deducting discount and underwriting fees. The notes are due March 1, 2041, and pay interest semi-annually at 6%. Total debt issuance costs of approximately $9 million were incurred and are being amortized to expense over the term of the notes. Approximately $470 million of the net proceeds were used to repay outstanding indebtedness under our revolving credit facility and the balance of the proceeds will be used for general corporate purposes. The notes are senior unsecured debt and rank pari passu with any of our other senior unsecured indebtedness with respect to the payment of both principal and interest. See Note 6. Derivative Instruments and Hedging Activities – Interest Rate Derivative Instrument.

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Annual Debt Maturities and FPSO Lease Payments   Annual maturities of outstanding debt and estimated annual FPSO lease payments are as follows:

(millions)	Debt Principal Payments	FPSO Lease Payments
September 30, 2011		
2011	$ -	$ 12
2012	728	72
2013	328	72
2014	200	72
2015	-	70
Thereafter	2,284	198
Total	$ 3,540	$ 496

New Credit Facility   On October 14, 2011, we entered into a credit agreement with certain commercial lending institutions (the Credit Agreement) which provides for a new $3.0 billion unsecured five-year revolving credit facility (the New Credit Facility). The New Credit Facility replaces our $2.1 billion credit facility maturing December 9, 2012. Also on October 14, 2011, we borrowed $400 million under the New Credit Facility, which was used to repay outstanding borrowings under and to terminate the $2.1 billion credit facility.

The New Credit Facility (i) provides for an initial commitment of $3.0 billion with an option to increase the overall commitment amount by up to an additional $1.0 billion, subject to the consent of any increasing lenders, (ii) will mature on October 14, 2016, (iii) provides for facility fee rates that range from 12.5 basis points to 30 basis points per year depending upon our credit rating, (iv) includes sub-facilities for short-term loans and letters of credit up to an aggregate amount of $500 million under each sub-facility and (iv) provides for interest rates that are based upon the Eurodollar rate plus a margin that ranges from 100 basis points to 145 basis points depending upon our credit rating.

The Credit Agreement requires that our total debt to capitalization ratio (as defined in the Credit Agreement), expressed as a percentage, not exceed 65% at any time. A violation of this covenant could result in a default under the Credit Agreement, which would permit the participating banks to restrict our ability to access the New Credit Facility and require the immediate repayment of any outstanding advances under the New Credit Facility.
The Credit Agreement does not restrict the payment of dividends on our common stock, except, if after giving effect thereto, an Event of Default shall have occurred and be continuing or been caused thereby.

The New Credit Facility is available for general corporate purposes. Certain lenders that are a party to the Credit Agreement have in the past performed, and may in the future from time to time perform, investment banking, financial advisory, lending or commercial banking services for us for which they have received, and may in the future receive, customary compensation and reimbursement of expenses.

Note 6. Derivative Instruments and Hedging Activities

Objective and Strategies for Using Derivative Instruments   In order to reduce commodity price uncertainty and enhance the predictability of cash flows relating to the marketing of our crude oil and natural gas, we enter into crude oil and natural gas price hedging arrangements with respect to a portion of our expected production. The derivative instruments we use include variable to fixed price commodity swaps, two-way and three-way collars, and basis swaps.

The fixed price swap, two-way collar, and basis swap contracts entitle us (floating price payor) to receive settlement from the counterparty (fixed price payor) for each calculation period in amounts, if any, by which the settlement price for the scheduled trading days applicable for each calculation period is less than the fixed strike price or floor price. We would pay the counterparty if the settlement price for the scheduled trading days applicable for each calculation period is more than the fixed strike price or ceiling price. The amount payable by us, if the floating price is above the fixed or ceiling price, is the product of the notional quantity per calculation period and the excess of the floating price over the fixed or ceiling price in respect of each calculation period. The amount payable by the counterparty, if the floating price is below the fixed or floor price, is the product of the notional quantity per calculation period and the excess of the fixed or floor price over the floating price in respect of each calculation period.

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A three-way collar consists of a two-way collar contract combined with a put option contract sold by us with a strike price below the floor price of the two-way collar. We receive price protection at the purchased put option floor price of the two-way collar if commodity prices are above the sold put option strike price. If commodity prices fall below the sold put option strike price, we receive the cash market price plus the delta between the two put option strike prices. This type of instrument allows us to capture more value in a rising commodity price environment, but limits our benefits in a downward commodity price environment.

We also enter into forward contracts or swap agreements to hedge exposure to interest rate risk.

While these instruments mitigate the cash flow risk of future reductions in commodity prices or increases in interest rates, they may also curtail benefits from future increases in commodity prices or decreases in interest rates.

See Note 7. Fair Value Measurements and Disclosures for a discussion of methods and assumptions used to estimate the fair values of our derivative instruments.

Counterparty Credit Risk Derivative instruments expose us to counterparty credit risk. Our commodity derivative instruments are currently with a diversified group of highly rated major banks or market participants, and we monitor and manage our level of financial exposure. Our commodity derivative contracts are executed under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net settled at the time of election.

We monitor the creditworthiness of our counterparties. However, we are not able to predict sudden changes in counterparties' creditworthiness. In addition, even if such changes are not sudden, we may be limited in our ability to mitigate an increase in counterparty credit risk. Possible actions would be to transfer our position to another counterparty or request a voluntary termination of the derivative contracts resulting in a cash settlement. Should one of these financial counterparties not perform, we may not realize the benefit of some of our derivative instruments under lower commodity prices or higher interest rates, and could incur a loss.

Interest Rate Derivative Instrument In January 2010, we entered into an interest rate forward starting swap to effectively fix the cash flows related to interest payments on our anticipated debt issuance. On February 15, 2011 we settled the interest rate swap, which had a net liability position of $40 million. Approximately $26 million, net of tax, was recorded in accumulated other comprehensive loss (AOCL) and is being reclassified to interest expense over the term of the 6% senior notes. The ineffective portion of the interest rate swap was de minimis. See Note 5. Debt.

Unsettled Derivative Instruments As of September 30, 2011, we had entered into the following crude oil derivative instruments:

				Swaps		Collars	
Period	Type of Contract	Index	Bbls Per Day	Weighted Average Fixed Price	Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
Instruments Entered Into as of September 30, 2011							
2011	Swaps		5,000	$ 85.52	$ -	$ -	$ -

		NYMEX WTI (1)					
2011	Two-Way Collars	NYMEX WTI	13,000	-	-	80.15	94.63
2011	Three-Way Collars	NYMEX WTI	12,000	-	58.33	78.33	100.71
2012	Swaps	NYMEX WTI	5,000	91.84	-	-	-
2012	Swaps	Dated Brent	8,000	89.06	-	-	-
2012	Three-Way Collars	NYMEX WTI	23,000	-	61.09	83.04	101.66
2012	Three-Way Collars	Dated Brent	3,000	-	70.00	95.83	105.00
2013	Swaps	Dated Brent	3,000	98.03	-	-	-
2013	Three-Way Collars	NYMEX WTI	5,000	-	65.00	85.00	113.63
2013	Three-Way Collars	Dated Brent	5,000	-	80.00	99.71	127.32
Instruments Entered Into During October 1-15, 2011							
2013	Three-Way Collars	Dated Brent	5,000	-	90.00	102.00	128.15

(1) West Texas Intermediate

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As of September 30, 2011, we had entered into the following natural gas derivative instruments:

Period	Type of Contract	Index	MMBtu Per Day	Swaps Weighted Average Fixed Price	Weighted Average Short Put Price	Collars Weighted Average Floor Price	Weighted Average Ceiling Price
Instruments Entered Into as of September 30, 2011							
2011	Swaps	NYMEX HH (1)	25,000	$ 6.41	$ -	$ -	$ -
2011	Two-Way Collars	NYMEX HH	140,000	-	-	5.95	6.82
2011	Three-Way Collars	NYMEX HH	50,000	-	4.00	5.00	6.70
2012	Swaps	NYMEX HH	30,000	5.10	-	-	-
2012	Three-Way Collars	NYMEX HH	110,000	-	4.44	5.25	6.66
2013	Swaps	NYMEX HH	30,000	5.25	-	-	-
2013	Three-Way Collars	NYMEX HH	50,000	-	4.00	5.25	5.59

(1) Henry Hub

As of September 30, 2011, we had entered into the following natural gas basis swaps:

Period	Index	Index Less Differential	MMBtu Per Day	Weighted Average Differential
2011	IFERC CIG (1)	NYMEX HH	140,000	$ (0.70)
2012	IFERC CIG	NYMEX HH	150,000	(0.52)

(1) Colorado Interstate Gas – Northern System

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Fair Value Amounts and Gains and Losses on Derivative Instruments The fair values of derivative instruments in our consolidated balance sheets were as follows:

Fair Value of Derivative Instruments

	Asset Derivative Instruments				Liability Derivative Instruments			
	September 30, 2011		December 31, 2010		September 30, 2011		December 31, 2010	
(millions)	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity Derivative Instruments (Not Designated as Hedging Instruments)	Current Assets	$ 87	Current Assets	$ 62	Current Liabilities	$ 6	Current Liabilities	$ 24
	Noncurrent Assets	44	Noncurrent Assets	-	Noncurrent Liabilities	-	Noncurrent Liabilities	51
Interest Rate Derivative Instruments (Designated as Hedging Instruments)	Current Assets	-	Current Assets	-	Current Liabilities	-	Current Liabilities	63
Total		$ 131		$ 62		$ 6		$ 138

The effect of derivative instruments on our consolidated statements of operations was as follows:

Commodity Derivative Instruments Not Designated as Hedging Instruments
Amount of Gain on Derivative Instruments Recognized in Income

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions)	2011	2010	2011	2010
Realized Mark-to-Market Gain	$ (22)	$ (33)	$ (39)	$ (65)
Unrealized Mark-to-Market Gain	(300)	(5)	(140)	(215)
Total Gain on Commodity Derivative Instruments	$ (322)	$ (38)	$ (179)	$ (280)

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Derivative Instruments in Cash Flow Hedging Relationships

	Amount of (Gain) Loss on Derivative Instruments Recognized in Other Comprehensive (Income) Loss		Amount of (Gain) Loss on Derivative Instruments Reclassified from Accumulated Other Comprehensive Loss	
	2011	2010	2011	2010
(millions)				
Three Months Ended September 30,				
Commodity Derivative Instruments in Previously Designated Cash Flow Hedging Relationships (1)				
Crude Oil Derivative Instruments	$ -	$ -	$ -	$ 5
Natural Gas Derivative Instruments	-	-	-	-
Interest Rate Derivative Instruments in Cash Flow Hedging Relationships	-	47	-	-
Total	$ -	$ 47	$ -	$ 5
Nine Months Ended September 30,				
Commodity Derivative Instruments in Previously Designated Cash Flow Hedging Relationships (1)				
Crude Oil Derivative Instruments	$ -	$ -	$ -	$ 14
Natural Gas Derivative Instruments	-	-	-	1
Interest Rate Derivative Instruments in Cash Flow Hedging Relationships	(23)	141	1	-
Total	$ (23)	$ 141	$ 1	$ 15

(1) Includes effect of commodity derivative instruments previously accounted for as cash flow hedges. All net derivative gains and losses that were deferred in AOCL as a result of previous cash flow hedge accounting, had been reclassified to earnings by December 31, 2010.

AOCL at September 30, 2011 included deferred losses of $27 million, net of tax, related to interest rate derivative instruments. This amount will be reclassified to earnings as an adjustment to interest expense over the terms of our senior notes due April 2014 and March 2041. Approximately $2 million of deferred losses (net of tax) will be reclassified to earnings during the next 12 months and will be recorded as an increase in interest expense.

Note 7. Fair Value Measurements and Disclosures

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Certain assets and liabilities are measured at fair value on a recurring basis in our consolidated balance sheets. The following methods and assumptions were used to estimate the fair values:

Cash, Cash Equivalents, Accounts Receivable and Accounts Payable The carrying amounts approximate fair value due to the short-term nature or maturity of the instruments.

Mutual Fund Investments Our mutual fund investments, which primarily include assets held in a rabbi trust, consist of various publicly-traded mutual funds that include investments ranging from equities to money market instruments. The fair values are based on quoted market prices for identical assets.

Commodity Derivative Instruments Our commodity derivative instruments consist of variable to fixed price commodity swaps, two-way and three-way collars, and basis swaps. We estimate the fair values of these instruments based on published forward commodity price curves as of the date of the estimate. The discount rate used in the discounted cash flow projections is based on published LIBOR rates, Eurodollar futures rates and interest swap rates. The fair values of commodity derivative instruments in an asset position include a measure of counterparty nonperformance risk, and the fair values of commodity derivative instruments in a liability position include a measure of our own nonperformance risk, each based on the current published credit default swap rates. In addition, for collars, we estimate the option values of the put options sold (for three-way collars) and the contract floors and ceilings (for two-way and three-way collars) using an option pricing model which takes into account market volatility, market prices and contract terms. See Note 6. Derivative Instruments and Hedging Activities.

Interest Rate Derivative Instrument We estimated the fair value of our forward starting swap based on published interest rate yield curves as of the date of the estimate. The fair values of interest rate derivative instruments in an asset position include a measure of counterparty nonperformance risk, and the fair values of interest rate derivative instruments in a liability position include a measure of our own nonperformance risk, each based on the current published credit default swap rates. See Note 6. Derivative Instruments and Hedging Activities.

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Deferred Compensation Liability   The value is dependent upon the fair values of mutual fund investments and shares of our common stock held in a rabbi trust. See Mutual Fund Investments above.

Measurement information for assets and liabilities that are measured at fair value on a recurring basis was as follows:

	Fair Value Measurements Using				
	Quoted Prices in Active Markets (Level 1) (1)	Significant Other Observable Inputs (Level 2) (2)	Significant Unobservable Inputs (Level 3) (3)	Adjustment (4)	Fair Value Measurement
(millions)					
September 30, 2011					
Financial Assets					
Mutual Fund Investments	$ 101	$ -	$ -	$ -	$ 101
Commodity Derivative Instruments	-	174	-	(43)	131
Financial Liabilities					
Commodity Derivative Instruments	-	(49)	-	43	(6)
Portion of Deferred Compensation					
Liability Measured at Fair Value	(152)	-	-	-	(152)
December 31, 2010					
Financial Assets					
Mutual Fund Investments	$ 112	$ -	$ -	$ -	$ 112
Commodity Derivative Instruments	-	106	-	(44)	62
Financial Liabilities					
Commodity Derivative Instruments	-	(119)	-	44	(75)
Interest Rate Derivative Instrument	-	(63)	-	-	(63)
Portion of Deferred Compensation Liability					
Measured at Fair Value	(178)	-	-	-	(178)

(1) Level 1 measurements are fair value measurements which use quoted market prices (unadjusted) in active markets for identical assets or liabilities. We use Level 1 inputs when available as Level 1 inputs generally provide the most reliable evidence of fair value.
(2) Level 2 measurements are fair value measurements which use inputs, other than quoted prices included within Level 1, which are observable for the asset or liability, either directly or indirectly.
(3) Level 3 measurements are fair value measurements which use unobservable inputs.
(4) Amount represents the impact of master netting agreements that allow us to net cash settle asset and liability positions with the same counterparty.

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Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are measured at fair value on a nonrecurring basis in our consolidated balance sheets. The following methods and assumptions were used to estimate the fair values:

Asset Impairments We determined that the carrying amounts of certain onshore US assets were not recoverable from future cash flows and, therefore, were impaired. The assets were reduced to their estimated fair values. Information about the impaired assets is as follows:

Description (millions)	Fair Value Measurements Using Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Book Value (1)	Total Pre-tax (Non-cash) Impairment Loss
Three Months Ended September 30, 2011					
Impaired Oil and Gas Properties	$ -	$ -	$ -	$ -	$ -
Three Months Ended September 30, 2010					
Impaired Oil and Gas Properties	-	-	48	148	100
Nine Months Ended September 30, 2011					
Impaired Oil and Gas Properties	$ -	$ -	$ 32	$ 171	$ 139
Nine Months Ended September 30, 2010					
Impaired Oil and Gas Properties	-	-	48	148	100

(1) Amount represents net book value at date of assessment.

The fair values of the properties were determined as of the date of the assessment using discounted cash flow models. The discounted cash flows were based on management's expectations for the future. Inputs included estimates of future oil and gas production, commodity prices based on published forward commodity price curves as of the date of the estimate, estimated operating and development costs, and a risk-adjusted discount rate. See Note 4. Asset Impairments.

Additional Fair Value Disclosures

Debt The fair value of fixed-rate debt is estimated based on the published market prices for the same or similar issues. The carrying amounts of floating-rate debt approximate fair value because the interest rate paid on such debt was set for periods of three months or less. The carrying amounts of the CONSOL installment payments approximate fair value because they have been discounted at the prevailing market rates for similar instruments. See Note 5. Debt.

Fair value information regarding our debt is as follows:

	September 30, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
(millions)				
Long-Term Debt, Net of Unamortized Discount (1)	$ 3,511	$ 4,031	$ 1,977	$ 2,302

(1) Excludes FPSO lease obligation.

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Note 8. 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:

(millions)	Nine Months Ended September 30,
Capitalized Exploratory Well Costs, Beginning of Period	$ 466
Additions to Capitalized Exploratory Well Costs Pending Determination of Proved Reserves	158
Reclassified to Proved Oil and Gas Properties Based on Determination of Proved Reserves (1)	(55)
Capitalized Exploratory Well Costs Charged to Expense	(15)
Capitalized Exploratory Well Costs, End of Period	$ 554

(1) Includes $13 million related to the Flyndre project in the North Sea.

The following table provides an aging of capitalized exploratory well costs (suspended 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:

(millions)	September 30, 2011	December 31, 2010
Exploratory Well Costs Capitalized for a Period of One Year or Less	$ 196	$ 166
Exploratory Well Costs Capitalized for a Period Greater Than One Year After Completion of Drilling	358	300
Balance at End of Period	$ 554	$ 466
Number of Projects with Exploratory Well Costs That Have Been Capitalized for a Period Greater Than One Year After Completion of Drilling	10	9

The following table provides a further aging of those exploratory well costs that have been capitalized for a period greater than one year since the completion of drilling as of September 30, 2011:

		Suspended Since		
(millions)	Total	2010	2009	2008 & Prior
Country/Project				
Offshore Equatorial Guinea				
Blocks O and I	$ 113	$ 7	$ 19	$ 87
Offshore Cameroon				
YoYo	39	1	2	36
Offshore Israel				
Dalit	22	1	21	-
Deepwater Gulf of Mexico				

Deep Blue	73	54	19	-
Gunflint	58	2	6	50
Redrock	21	1	2	18
North Sea				
Selkirk	23	1	1	21
Other				
3 projects of $10 million or less each	9	9	-	-
Total	$ 358	$ 76	$ 70	$ 212

Blocks O and I   Blocks O and I are crude oil, natural gas and natural gas condensate discoveries. During third quarter 2011 we continued to evaluate results of the appraisal well at the Carmen/Diega prospect.

YoYo   YoYo is a 2007 natural gas and condensate discovery. We have acquired and processed additional 3-D seismic information.

Dalit   Dalit is a 2009 natural gas discovery. We are currently working with our partners on a cost-effective development plan.

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Deep Blue   Deep Blue (Green Canyon Block 723) is an exploratory well which found hydrocarbon pay in multiple intervals. When the deepwater Gulf of Mexico moratorium was announced in May 2010, we were required to suspend sidetrack drilling activities. During third quarter 2011, we obtained approval for a drilling permit and resumed exploration drilling.

Gunflint   Gunflint (Mississippi Canyon Block 948) is a 2008 crude oil discovery. Our plans to conduct appraisal drilling activities in 2010 were delayed by the deepwater Gulf of Mexico moratorium. Once a drilling permit is approved, we plan to resume drilling activities. We are also reviewing host platform options.

Redrock   Redrock (Mississippi Canyon Block 204) is a 2006 natural gas/condensate discovery and is currently considered a co-development candidate with Raton South (Mississippi Canyon Block 292). We are in the process of developing Raton South as a subsea tieback to a host platform at Viosca Knoll Block 900. We plan to develop Redrock after Raton South commences production, which is currently expected to occur by the end of 2011.

Selkirk   The Selkirk project is located in the UK sector of the North Sea. Capitalized costs to date primarily consist of the cost of drilling an exploratory well. We are currently working with our partners on a cost-effective development plan, including selection of a host facility.

Note 9. 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,	
(millions)	2011	2010
Asset Retirement Obligations, Beginning Balance	$ 253	$ 232
Liabilities Incurred	2	14
Liabilities Settled	(19)	(35)
Revision of Estimate	9	11
Accretion Expense	15	13
Asset Retirement Obligations, Ending Balance	$ 260	$ 235

Liabilities settled in 2011 related primarily to deepwater and shelf properties in the Gulf of Mexico. Liabilities settled in 2010 related to US onshore assets sold and a Gulf of Mexico shelf asset.

Liabilities incurred in 2010 were due primarily to the Central DJ Basin asset acquisition.

Accretion expense is included in depreciation, depletion and amortization (DD&A) expense in the consolidated statements of operations.

Note 10.   Employee Benefit Plans

We have a noncontributory, tax-qualified defined benefit pension plan covering employees who were hired prior to May 1, 2006. 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. Net periodic benefit cost related to the retirement and restoration plans was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
(millions)				
Service Cost	$ 3	$ 4	$ 10	$ 11
Interest Cost	3	3	10	10
Expected Return on Plan Assets	(4)	(3)	(11)	(10)
Other	2	1	5	4
Net Periodic Benefit Cost	$ 4	$ 5	$ 14	$ 15

During the nine months ended September 30, 2011, we made cash contributions of $23 million to the pension plan.

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Note 11. Stock-Based Compensation

We recognized stock-based compensation expense as follows:

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
(millions)				
Stock-Based Compensation Expense	$ 15	$ 13	$ 43	$ 40
Tax Benefit Recognized	(5)	(5)	(15)	(14)

During the nine months ended September 30, 2011, we granted stock options and awarded shares of restricted stock (subject to service conditions) as follows:

	Number Granted/Awarded	Weighted Average Fair Value
Stock Options	985,503	$30.18
Shares of Restricted Stock	403,097	$90.34

On April 26, 2011, our stockholders approved the amendment and restatement of our 1992 Stock Option and Restricted Stock Plan to increase the number of shares of common stock authorized for issuance under the plan from 24 million to 31 million and modify certain plan provisions.

Note 12. Basic and Diluted Earnings Per Share

Basic earnings per share of common stock is computed using the weighted average number of shares of common stock outstanding during each period. The diluted earnings per share of common stock may include the effect of outstanding stock options, shares of restricted stock, or shares of our common stock held in a rabbi trust except in periods in which there is a net loss. The following table summarizes the calculation of basic and diluted earnings per share:

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
(millions, except per share amounts)				
Net Income	$ 441	$ 232	$ 749	$ 673
Earnings Adjustment from Assumed Conversion of				
Dilutive Shares of Common Stock in Rabbi Trust (1)	(12)	-	(10)	3
Net Income Used for Diluted Earnings Per Share Calculation	$ 429	$ 232	$ 739	$ 676
	177	175	176	175

Weighted Average Number of Shares Outstanding, Basic								
Incremental Shares from Assumed Conversion of								
Dilutive Stock Options, Restricted Stock and Shares of Common Stock in Rabbi Trust		3		2		3		3
Weighted Average Number of Shares Outstanding, Diluted		180		177		179		178
Earnings Per Share, Basic	$	2.50	$	1.33	$	4.25	$	3.86
Earnings Per Share, Diluted		2.39		1.31		4.12		3.80
Number of antidilutive stock options and shares of restricted								
stock excluded from calculation above		1		2		2		2

(1) Consistent with GAAP, when dilutive, deferred compensation gains or losses, net of tax, are excluded from net income while the NBL shares held in the rabbi trust are included in the diluted share count. For this reason, the diluted earnings per share calculations for the three and nine months ended September 30, 2011 exclude deferred compensation gains, net of tax; and the diluted earnings per share calculation for the nine months ended September 30, 2010 excludes a deferred compensation loss, net of tax.

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Note 13. Income Taxes

The income tax provision consists of the following:

	Three Months Ended September 30, 2011	2010	Nine Months Ended September 30, 2011	2010
(millions)				
Current	$ 179	$ 42	$ 289	$ 180
Deferred	102	24	147	109
Total Income Tax Provision	$ 281	$ 66	$ 436	$ 289
Effective Tax Rate	39 %	22 %	37 %	30 %

Our effective tax rate increased for the first nine months of 2011 as compared with the first nine months of 2010. This was primarily due to the changes in Israeli and UK tax law discussed below and to a $16 million increase in the valuation allowance against our deferred tax asset for foreign tax credits. Partially offsetting this increase was the impact of greater earnings from equity method subsidiaries in 2011, which has the effect of decreasing the rate when we have pre-tax income. In third quarter 2010, we reversed a $28 million valuation allowance which had been established against a deferred tax asset of the same amount for the future foreign tax credits associated with deferred tax liabilities recorded by foreign branch operations and recorded a corresponding reduction in income tax expense. Finally, the rate for the first nine months of 2010 was increased by a nondeductible allocation of goodwill to assets sold.

Changes in Israeli Tax Law In March 2011, the Israeli government enacted the Oil Profits Taxation Law, 2011, which imposes additional income tax on oil and gas production. The Israeli government also repealed the percentage depletion deduction and made certain changes to the rules for deducting tangible and intangible development costs. We expect these changes to increase our 2011 consolidated effective income tax rate by approximately two percentage points. We expect no remeasurement of our deferred tax assets or liabilities as of December 31, 2010.

Changes in UK Tax Law Also in March 2011, the UK government announced that the Finance Bill 2011 will increase the rate of the Supplementary Charge levied on oil and gas income in the UK from 20% to 32% effective March 24, 2011. This change, which became law on July 19, 2011, increased the tax rate on our UK oil and gas income from 50% to 62% and our 2011 consolidated effective income tax rate by approximately four percentage points. The change also resulted in a remeasurement of our UK deferred tax liability as of December 31, 2010 to reflect the higher effective rate. As a result, we recorded a $34 million increase in both our deferred income tax liability and deferred income tax expense during third quarter 2011. These changes are reflected in our balance sheet and results of operations at September 30, 2011.

Years Remaining Open to Examination In our major tax jurisdictions, the earliest years remaining open to examination are as follows: US – 2006, Equatorial Guinea – 2007, Israel – 2008, UK – 2007, the Netherlands – 2009, and China – 2006.

Note 14. Comprehensive Income

Comprehensive income includes net income and certain items recorded directly to shareholders' equity and classified as AOCL. Comprehensive income was calculated as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
(millions)				
Net Income	$ 441	$ 232	$ 749	$ 673
Other Items of Comprehensive Income (Loss)				
Oil and Gas Cash Flow Hedges				
Realized Losses Reclassified Into Earnings	-	5	-	15
Less Tax Provision	-	(2)	-	(5)
Interest Rate Cash Flow Hedges				
Unrealized Change in Fair Value	-	(47)	23	(141)
Less Tax Provision	-	16	(8)	49
Net Change in Other	1	1	4	2
Other Comprehensive Income (Loss)	1	(27)	19	(80)
Comprehensive Income	$ 442	$ 205	$ 768	$ 593

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Noble Energy, Inc.

Notes to Consolidated Financial Statements
(unaudited)

Note 15. Segment Information

We have operations throughout the world and manage our operations by country. The following information is grouped into five components that are all primarily in the business of crude oil and natural gas exploration, development, and acquisition: the United States; West Africa (Equatorial Guinea, Cameroon, Senegal and Guinea-Bissau); Eastern Mediterranean (Israel and Cyprus); the North Sea (UK and the Netherlands); and Other International and Corporate. Other International includes China, Ecuador (through May 2011), and new ventures.

(millions)	Consolidated	United States	West Africa	Eastern Mediter-ranean	North Sea	Other Int'l and Corporate
Three Months Ended September 30, 2011						
Revenues from Third Parties	$ 874	$ 520	$ 153	$ 108	$ 45	$ 48
Income from Equity Method Investees	50	-	50	-	-	-
Total Revenues	924	520	203	108	45	48
DD&A	225	180	13	8	10	14
Gain on Commodity Derivative Instruments	(322)	(213)	(109)	-	-	-
Income (Loss) Before Income Taxes	722	418	270	88	23	(77)
Three Months Ended September 30, 2010						
Revenues from Third Parties	$ 726	$ 458	$ 64	$ 63	$ 99	$ 42
Reclassification from AOCL (1)	(5)	(5)	-	-	-	-
Income from Equity Method Investees	34	-	34	-	-	-
Total Revenues	755	453	98	63	99	42
DD&A	231	184	10	7	20	10
Gain on Divestiture (2)	(114)	(114)	-	-	-	-
Asset Impairments (3)	100	100	-	-	-	-
(Gain) Loss on Commodity Derivative Instruments	(38)	(49)	11	-	-	-
Income (Loss) Before Income Taxes	298	211	64	51	59	(87)
Nine Months Ended September 30, 2011						
	$ 2,632	$ 1,578	$ 401	$ 236	$ 271	$ 146

Revenues from Third Parties						
Income from Equity Method Investees	146	-	146	-	-	-
Total Revenues	2,778	1,578	547	236	271	146
DD&A	681	534	30	19	62	36
Gain on Divestiture (2)	(26)	(1)	-	-	-	(25)
Asset Impairments (3)	139	137	-	-	2	-
Gain on Commodity Derivative Instruments	(179)	(163)	(16)	-	-	-
Income (Loss) Before Income Taxes	1,185	631	460	184	161	(251)
Nine Months Ended September 30, 2010						
Revenues from Third Parties	$ 2,169	$ 1,425	$ 243	$ 144	$ 227	$ 130
Reclassification from AOCL (1)	(15)	(15)	-	-	-	-
Income from Equity Method Investees	85	-	85	-	-	-
Total Revenues	2,239	1,410	328	144	227	130
DD&A	662	543	28	18	45	28
Gain on Divestiture (2)	(114)	(114)	-	-	-	-
Asset Impairments (3)	100	100	-	-	-	-
Gain on Commodity Derivative Instruments	(280)	(277)	(3)	-	-	-
Income (Loss) Before Income Taxes	962	681	258	110	132	(219)
September 30, 2011						
Goodwill	$ 696	$ 696	$ -	$ -	$ -	$ -
Total Assets	15,833	10,921	2,544	1,540	625	203
December 31, 2010						
Goodwill	696	696	-	-	-	-
Total Assets	13,282	9,091	2,270	919	770	232

Noble Energy, Inc.
Notes to Consolidated Financial Statements
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(1) Revenues include decreases resulting from hedging activities. The decreases resulted from hedge gains and losses that were deferred in AOCL, as a result of previous cash flow hedge accounting, and subsequently reclassified to revenues. All hedge gains and losses had been reclassified to revenues by December 31, 2010.

(2) See Note 3. Acquisitions and Divestitures.

(3) See Note 4. Asset Impairments.

Note 16. Commitments and Contingencies

Legal Proceedings 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 believe that the ultimate disposition of such proceedings will not have a material adverse effect on our financial position, results of operations or cash flows.

See also Part II. Other Information, Item 1. Legal Proceedings for further information on pending cases.

Marcellus Shale Joint Venture Partnership See Note 3. Acquisitions and Dispositions for a description of the CONSOL Carried Cost Obligation and MARC.

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

EXECUTIVE OVERVIEW

We are an independent energy company engaged in global crude oil and natural gas exploration and production. Our strategy is to achieve growth in earnings and cash flows through the continued expansion of a high quality portfolio of assets that is diversified among US and international projects, crude oil and natural gas, and near, medium and long-term opportunities.

Our accompanying consolidated financial statements, including the notes thereto, contain detailed information that should be referred to in conjunction with the following discussion.

Our financial results for third quarter 2011 included:

- net income of $441 million, as compared with $232 million for third quarter 2010;
- gain on commodity derivative instruments of $322 million (including unrealized mark-to-market gain of $300 million) as compared with a gain on commodity derivative instruments of $38 million (including unrealized mark-to-market gain of $5 million) for third quarter 2010;
- diluted earnings per share of 2.39, as compared with $1.31 for third quarter 2010;
- cash flow provided by operating activities of $556 million, as compared with $608 million for third quarter 2010;
- capital spending, on a cash basis, of $1.2 billion (including $592 million for Marcellus shale assets and equity method investments), as compared with $536 million for third quarter of 2010;
- total liquidity of almost $3.0 billion at the end of the period as compared with $2.8 billion at December 31, 2010; and
- ratio of debt-to-book capital of 34% as compared with 25% at December 31, 2010.

Operational events for third quarter 2011 included:

United States

- produced a record 65 MBoe/d in the DJ Basin with horizontal production exiting the quarter at over 11 MBoe/d;
- completed 25 new horizontal Niobrara wells and added a fifth rig to the program;
- established a new significant position in the Marcellus shale with the acquisition of 314,000 net acres and 50 MMcf/d of existing net production;

International

- Aseng FPSO departed shipyard for Equatorial Guinea;
- record natural gas sales in Israel of 228 MMcf/d, an increase of 28% from the third quarter last year;
- drilled two wells at the Noa development project offshore Israel, ahead of schedule and below anticipated costs; and
- spud the Cyprus A prospect on Block 12 offshore Cyprus.

Entry into Marcellus Shale Joint Venture

On September 30, 2011, we entered an agreement with CONSOL to jointly develop oil and gas assets in the Marcellus shale areas of southwest Pennsylvania and northwest West Virginia. The Marcellus shale joint venture strengthens and rebalances our portfolio, providing an entirely new, material growth area, which will impact future reserves, production, and cash flows. This transaction complements and further strengthens our US portfolio by adding a high quality asset with substantial growth potential. It significantly increases our inventory of low risk repeatable projects while exposing us to more North American unconventional resources, and we believe the area is one of the most economically attractive natural gas developments onshore US due to its low operating and development cost structure and close access to Northeastern gas markets. The Marcellus shale joint venture, combined with our other domestic projects in the DJ Basin and the deepwater Gulf of Mexico, provide balance to our rapidly expanding international programs.

Under the terms of the agreement, we acquired 50% interests in 628,000 net undeveloped acres, existing Marcellus production, and existing infrastructure for approximately $1.2 billion. Payments will be made in three equal annual installments, with the first installment made at closing. We will pay an additional $2.1 billion in the form of a carry of CONSOL's drilling and completion costs. The carry, which we expect to extend over approximately eight years, is capped at $400 million annually and suspended if average Henry Hub natural gas prices fall and remain below $4 per MMBtu for three consecutive months. Initially, we will be the designated operator of the wet gas areas (areas with more condensate or liquids) and CONSOL will be the designated operator of the dry gas areas (areas with little or no condensate or liquids).

As a result of the transaction, we acquired net proved reserves of approximately 400 Bcfe, based on reserves estimates as of December 31, 2010, and 50 MMcf/d of existing production at September 30, 2011.

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As a result of this transaction, we are now focusing on three core areas within the US: the DJ Basin; the Marcellus shale; and the deepwater Gulf of Mexico. We are also considering the divestiture of certain mature, non-core onshore US properties from our portfolio.

See Item 1. Financial Statements – Note 3. Acquisitions and Divestitures and Note 5. Debt, Recent Developments in the Marcellus Shale, Liquidity and Capital Resources, and Part II. Other Information. Item 1A. Risk Factors Our entry into the Marcellus shale through our joint venture with CONSOL will subject us to certain financial, operational and legal obligations and additional risks associated with crude oil and natural gas development activities in that region.

Recent Developments in the Eastern Mediterranean

Cyprus We are currently drilling the Cyprus A-1 exploration well in Block 12, offshore Cyprus. In 1974 the island of Cyprus was partitioned into two parts; the Republic of Cyprus with the majority of the south under its effective control, and the Turkish controlled area in the north, which calls itself the Turkish Republic of Northern Cyprus and is recognized only by Turkey. The United Nations recognizes the sovereignty of the Republic of Cyprus over the entire island. The Republic of Cyprus has been a member of the European Union since May 1, 2004. The Turkish government opposes the current exploratory activities being conducted by the Republic of Cyprus, claiming it will have a detrimental effect on reunification negotiations, which have been conducted over three decades and are currently being brokered by the United Nations. While Turkey has voiced its opposition to the drilling activity, the European Union, Russia and the US have supported Cyprus' right to drill.

Israel Israel's diplomatic relations with Turkey and Egypt have been deteriorating. In September 2011, Turkey downgraded diplomatic and trade ties with Israel.

These events have increased the political and social uncertainty in the region; and, at this time, we are uncertain of the outcome of these events. Disruptions caused by territorial or boundary disputes could have an adverse effect on our results of operations and cash flows and reduce the fair values of our properties, resulting in impairment charges. In addition, we may not have enough insurance to cover any losses.

Recent Developments Surrounding the Use of Hydraulic Fracturing and Production from Shale Formations

Hydraulic fracturing is a process commonly used to stimulate production of natural gas and/or oil from dense subsurface rock formations, including shale. We find that the use of hydraulic fracturing is necessary to produce commercial quantities of crude oil and natural gas from many reservoirs, including the DJ Basin. We are in the process of securing additional water rights that will support our DJ Basin drilling program and implementing a pilot water recycling program.

We also expect to use hydraulic fracturing in the development of the Marcellus shale. Our joint development agreement with CONSOL provides us with access to water resources, which we believe will be adequate to execute our development program, and we anticipate the ability to recycle most of the water produced from hydraulic fracturing activities in the Marcellus shale.

As the use of hydraulic fracturing has expanded in recent years, public concern has grown over its possible effects on the environment, including drinking water supplies. We do not believe that properly conducted hydraulic fracturing poses a meaningful risk to water supplies. However, the use of hydraulic fracturing continues to be the subject of controversy in the US where it is often opposed by environmental activists as well as by local citizens in certain areas.

Federal and state rules and regulations governing the reporting and use of hydraulic fracturing continue to evolve. For example, on July 28, 2011, the Environmental Protection Agency (EPA) issued proposed rules that would subject all oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants programs. The EPA proposed rules also include NSPS standards for completions of hydraulically fractured gas wells which would be applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the proposed rules include maximum achievable control technology standards for certain equipment not currently subject to such standards. Final action on the proposed rules is expected no later than February 28, 2012.

Earlier in 2011, the US Secretary of Energy formed the Shale Gas Production Subcommittee (Subcommittee), a subcommittee of the Secretary of Energy Advisory Board. The Subcommittee was charged with making recommendations to improve the safety and environmental performance of hydraulic fracturing. On August 18, 2011, the Subcommittee issued its 90-Day Report (Report), which focused exclusively on the production of natural gas (and some liquid hydrocarbons) from shale formations with hydraulic fracturing stimulation in either vertical or horizontal wells. The Subcommittee identified four primary areas of concern including possible water pollution, air pollution, disruption of the community during production, and potential for adverse impact on communities and ecosystems. The Subcommittee also set forth a list of recommendations addressing, among other areas, communications, air quality, protection of water supply and quality, disclosure of fracturing fluid composition, reduction of diesel fuel use, continuous development of best practices, and federal sponsorship of research and development with respect to unconventional gas. The Subcommittee is scheduled to issue a 180-day final report in November 2011. We will continue to monitor the impact the Subcommittee’s recommendations, and any resulting rule-making activities, could have on our exploration and development activities in shale formations.

In June 2011, Texas adopted a law requiring disclosure of certain information regarding the components used in the hydraulic-fracturing process.

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We continue to monitor new and proposed legislation to assess the potential impact on our operations. We are currently evaluating the possible impact any proposed rules, such as those described above, could have on our business. Any additional federal, state or local restrictions on hydraulic fracturing that may be imposed in areas in which we conduct business could significantly increase our operating, capital and compliance costs as well as delay our ability to develop oil and gas reserves.

See Part II. Other Information. Item 1A. Risk Factors Our ability to produce crude oil and natural gas economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling operations or are unable to dispose of or recycle the water we use at a reasonable cost and in accordance with applicable environmental rules.

Recent Developments in the Marcellus Shale

On September 7, 2011, an intermediate appellate court (Superior Court) of Pennsylvania issued an opinion in Butler v. Powers regarding the meaning of a deed. As a result, traditional views of how ownership of shale gas is determined in that state have been called into question. The issue is whether shale gas is different from other natural gas and should be considered part of mineral rights, rather than oil and gas rights, because it is contained inside rock. At this time, no case law or interpretation of existing law has changed, nor has there been an indication that either the Superior Court or the Pennsylvania Supreme Court will seek to change existing law. Based upon the limited review performed to date, we believe that any adverse decision in the pending case would have minimal adverse impact upon the assets acquired from CONSOL.

On October 3, 2011, Governor Tom Corbett of Pennsylvania announced his plan for state oversight of the Marcellus shale natural gas industry. His plan includes numerous recommendations recently proposed by the Marcellus Shale Advisory Commission. Standards related to unconventional drilling would include increases in well setback distances, increases in bonding requirements, increases in penalties, expansion of the distance from a well for which a driller can be liable for environmental damage, and broadening of the Department of Environmental Protection’s authority to withhold or revoke permits. The plan also allows for an impact fee, which would be adopted by counties for use by local communities experiencing the actual impacts of drilling. The fee will be used by local governments, counties and state agencies that are involved in Marcellus Shale natural gas drilling. We are monitoring rule-making activities of the Pennsylvania legislature to assess the possible impact any recommendations could have on our business. Enactment of an impact fee and/or other proposals would likely result in a lower rate of return on our development project.

See Part II. Other Information. Item 1A. Risk Factors Our entry into the Marcellus shale through our joint venture with CONSOL will subject us to certain financial, operational and legal obligations and additional risks associated with crude oil and natural gas development activities in that region and Our ability to produce crude oil and natural gas economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling operations or are unable to dispose of or recycle the water we use at a reasonable cost and in accordance with applicable environmental rules.

Impact of Amendments to Rule 318A

On August 9, 2011, the Colorado Oil and Gas Conservation Commission approved amendments to The Greater Wattenberg Area Special Well Location Rule 318A (Rule 318A), which addresses oil and gas well drilling, production, commingling and spacing in the Wattenberg field. The amendments, which became effective on October 1, 2011, remove the limit on the number of wells which can produce from a particular formation and address areas such as infill drilling, water sampling and waste management plans. We believe the amendments will enhance our horizontal well drilling program by removing the numerical limitation on wells, allowing wellbore spacing units and permitting wells to cross section lines.

Exploration Program Update

We have significant remaining exploration potential, primarily in the onshore US, deepwater Gulf of Mexico, offshore West Africa, offshore Eastern Mediterranean and other international areas where we hold acreage positions. Significant exploratory wells were in progress at September 30, 2011, and we expect to continue an active exploratory drilling program in fourth quarter 2011. We do not always encounter commercially productive reservoirs through our drilling operations and, as a result, dry hole cost could be significant. Updates of our significant exploration activities are as follows:

DJ Basin (US Onshore) We continue to acquire 3-D seismic information and appraise our acreage in Northern Colorado and Wyoming.

Deep Blue (Deepwater Gulf of Mexico) We obtained approval for a drilling permit and resumed exploratory drilling during third quarter 2011.

Dolphin 1 (Offshore Israel) We are in the process of drilling the Dolphin 1 prospect in the Hanna license, southwest of the Tamar gas field.

Leviathan (Offshore Israel) We are conducting appraisal drilling activities at the Leviathan-3 well.

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Cyprus A-1 (Offshore Cyprus) We are in the process of drilling the Cyprus A-1 exploratory well in Block 12.

Major Development Projects Update

During third quarter 2011, we continued to advance our major development projects, which we expect to deliver significant growth over the next several years. Updates on our significant development projects are as follows:

DJ Basin (US Onshore) We have increased our horizontal drilling activity targeting the Niobrara formation, completing 25 horizontal wells during the quarter. We recently added another drilling rig to our program and are currently running five horizontal drilling rigs.

Marcellus Shale Joint Venture (US Onshore) We are in the process of assuming operatorship of the wet gas areas. There are currently four horizontal rigs operating on the joint venture properties and we expect that an additional rig will be added during fourth quarter 2011. See Part II. Other Information. Item 1A. Risk Factors – Our entry into the Marcellus shale through our joint venture with CONSOL will subject us to certain financial, operational and legal obligations and additional risks associated with crude oil and natural gas development activities in that region.

Galapagos (Deepwater Gulf of Mexico) Installation of topside equipment at the host facility and subsea tiebacks for the Santa Cruz, Isabela and Santiago wells are progressing. We currently expect production to commence in early 2012.

Gunflint (Deepwater Gulf of Mexico) Once a drilling permit is approved, we plan to conduct appraisal drilling to help define the extent of the reservoir and a potential development scenario.

Aseng (Offshore Equatorial Guinea) The FPSO sailed for the Aseng field during third quarter and arrived on October 16, 2011. We currently expect production to commence by year end 2011. We have executed an oil sale, purchase, and marketing agreement with Glencore Energy UK Ltd for our share of Aseng production.

Alen (Offshore Equatorial Guinea) Platform fabrication is underway. We have commenced development drilling and currently expect production to commence by the end of 2013.

Carmen/Diega (Offshore Equatorial Guinea) We are evaluating drilling results and formulating a development plan.

West Africa Gas Project (Offshore Equatorial Guinea) The Equatorial Guinea Ministry of Mines, Industry and Energy is considering the development of an integrated gas project (Integrated project) which includes upstream gas projects, the required gas transportation system, and a second LNG train. A Coordinating Committee was formed to determine the viability and scope of the Integrated project. We have been appointed chair of the Coordinating Committee.

Tamar (Offshore Israel) Development drilling, platform fabrication and subsea production system installation are underway. Tamar remains on schedule for commissioning beginning in late 2012.

Noa (Offshore Israel) The Noa field will be developed as a subsea tieback to the Mari-B platform. Two development wells have been drilled, FEED (front end engineering and design) work continues, and bid packages are being evaluated. Production is expected to commence in the second half of 2012.

Leviathan (Offshore Israel) We are evaluating potential development scenarios for the Leviathan natural gas discovery and planning pre-FEED activities.

Leviathan-2 Insurance Recoveries

In May 2011, we ended drilling operations at the Leviathan-2 appraisal well location offshore Israel. During the drilling process, we identified water flowing to the sea floor from the wellbore. We are monitoring the wellbore and there are no indications of any hydrocarbons in the produced water.

The incident was a covered event under our well control insurance; therefore, we expect to recover most of the costs from insurance, subject to a deductible. The final amount to be recovered will be based on the cost to drill the Leviathan-3 replacement well down to the same depth at which the incident occurred, possible remediation activities and/or abandonment activities at the Leviathan-2 well, which have not yet been determined, and other factors. As of September 30, 2011, we had recorded a loss on involuntary conversion of $4 million. In addition, we wrote off the net book value of the asset and recorded a corresponding receivable for probable insurance claims of $25 million. We expect to continue to incur costs and submit claims in the normal course of business in 2011 and 2012 and expect the final amount recovered to increase from the current estimate. See Item 1. Financial Statements – Note 2. Basis of Presentation and Liquidity and Capital Resources – Insurance Recoveries, below.

Asset Impairments

We recorded asset impairment charges of $139 million during the first nine months of 2011 and $100 million during the first nine months of 2010. The impairments were primarily due to field performance and/or a low natural gas price environment. Future decreases in forward natural gas prices or other factors, such as significant increases in development or operating costs or unsatisfactory drilling results, could result in additional impairment charges. See Item 1. Financial Statements – Note 4. Asset Impairments and Note 7. Fair Value Measurements and Disclosures, and Potential for Future Asset Impairments, below.

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Divestitures

In May 2011, we completed the transfer of our assets in Ecuador to various government-affiliated entities. We received compensation for the offshore Amistad field assets and Block 3 PSC which was terminated by the government of Ecuador on November 25, 2010, as well as for the Machala Power Electricity concession and its associated assets and recorded a gain of approximately $26 million. In August 2010, we closed the sale of certain non-core assets in the Mid-Continent and Illinois Basin areas for sales proceeds of $552 million and recorded a gain of $114 million on the sale. See Item 1. Financial Statements – Note 3. Acquisitions and Divestitures.

Sales Volumes

On a BOE basis, total sales volumes were 3% lower third quarter 2011 as compared with third quarter 2010, and our mix of sales volumes was 37% global liquids, 36% international natural gas, and 27% US natural gas. International sales volumes were higher in Equatorial Guinea, due to more liftings, and Israel. US production decreased slightly year to year due to sales of mature, non-core properties in 2010. Our volumes for third quarter 2011 did not include natural gas in Ecuador, where our PSC was terminated in late 2010. In addition, we have suspended spot sales of natural gas from the Mari-B field in Israel in order to assure adequate supply to our customers under long-term sales contracts. See Results of Operations – Revenues, below.

Commodity Price Changes and Hedging

Average realized crude oil prices for third quarter 2011 increased 34% as compared with third quarter 2010 and were driven by stronger global crude oil markets.

Total average realized natural gas prices for third quarter 2011 increased 14% as compared with third quarter 2010 primarily due to higher international natural gas pricing.

We have hedged approximately 49% of our expected global crude oil production and 56% of our expected domestic natural gas production for the remainder of 2011.

OPERATING OUTLOOK

Our expected crude oil, natural gas and NGL production for 2011 may be impacted by several factors including:

- overall level and timing of capital expenditures which, as discussed below and dependent upon our drilling success, are expected to maintain our near-term production volumes;
- timing of major development project completion and initial production;
- ongoing development activity in the Wattenberg area and horizontal drilling in the Niobrara formation in the DJ Basin;
- ramp-up of development activity in the Marcellus shale;
- natural field decline in the deepwater Gulf of Mexico, Gulf Coast and Mid-Continent areas of our US operations and in the North Sea;
- variations in sales volumes of natural gas from the Alba field in Equatorial Guinea related to potential downtime at the methanol, LPG and/or LNG plants;
- Israeli demand for electricity which affects demand for natural gas as fuel for power generation, market growth and competing deliveries of natural gas from Egypt;
- variations in North Sea sales volumes due to potential FPSO downtime and timing of liftings;
- potential hurricane-related volume curtailments in the deepwater Gulf of Mexico and Gulf Coast areas;
-

potential winter storm-related volume curtailments in the Rocky Mountain and/or Marcellus shale areas of our US operations;
- potential pipeline and processing facility capacity constraints in the Rocky Mountain and/or Marcellus shale areas of our US operations; and
- potential purchases of producing properties and/or divestments of non-core operating assets.

2011 Capital Investment Program

Our 2011 capital program is expected to total approximately $3.0 billion, excluding our Marcellus shale joint venture acquisition costs. The capital program includes approximately $110 million for planned development in our new Marcellus shale core area during the remainder of 2011. We expect to accrue approximately $70 million for the Aseng FPSO lease obligation during 2011. We expect to contribute approximately $12 million in 2011 to CONE Gathering LLC to fund our share of the work program.

We expect that the 2011 capital investment program will be funded from cash flows from operations, cash on hand, and borrowings under our revolving credit facility and/or other financing such as our issuance of long-term debt in first quarter 2011. See Liquidity and Capital Resources.

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We will evaluate the level of capital spending throughout the year based on the following factors, among others:

- commodity prices;
- cash flows from operations;
- operating and development costs and possible inflationary pressures;
- permitting activity in the deepwater Gulf of Mexico;
- potential changes in the fiscal regimes of the US and other countries in which we operate;
- impact of implementation of the Dodd-Frank Act on our business practices, including, among others, requirements regarding the posting of cash collateral in hedging transactions;
- drilling results;
- property acquisitions and divestitures; and
- potential legislative or regulatory changes regarding the use of hydraulic fracturing.

Current Global Economic Situation, Changes in Fiscal Regimes and Market Regulations

The recovery from the global financial crisis has been slow and uneven. In the past few months various events, including the US debt downgrade, the European debt crisis, slower GDP growth rates, and reduced consumer demand, have increased economic uncertainty. Many governments are facing demands to increase social spending. Increased spending on public entitlement and/or economic stimulus programs, coupled with a reduced tax base, has resulted in significant budget deficits in many countries. Against this backdrop, global commodity prices have recovered significantly.

In order to address negative fiscal situations and initiate deficit reduction measures, many governments are seeking additional revenue sources, including increases in government take from oil and gas projects. Recently, the President of the United States proposed the American Jobs Act of 2011 (American Jobs Act). The American Jobs Act contains various measures, including tax increases and other revenue-raising proposals, designed to reduce the federal deficit by $3 trillion. Certain proposals, if enacted, would eliminate key US federal income tax incentives currently available to oil and natural gas exploration and production companies including: the repeal of the percentage depletion allowance for oil and natural gas properties, the elimination of current deductions for intangible drilling and development costs, the elimination of the deduction for certain domestic production activities, and an extension of the amortization period for certain geological and geophysical expenditures. In addition, the Joint Select Committee on Deficit Reduction, a panel established by the recent Budget Control Act of 2011, is charged with recommending at least $1.2 trillion in deficit reductions by November 23, 2011.

Future economic and political changes in the US or other countries in which we operate could result in governments enacting additional taxes and/or other market interventions, which could be detrimental to oil and gas companies. Any such changes could have an adverse effect on our financial position, results of operations and cash flows.

During the first nine months of 2011, fiscal regime changes occurred in both Israel and the UK.

Israel   In March 2011, the Israeli government enacted the Oil Profits Taxation Law, 2011, which imposes additional income tax on oil and gas production. The Israeli government also repealed the percentage depletion deduction and made certain changes to the rules for deducting tangible and intangible development costs. We currently expect these changes to increase our 2011 consolidated income tax expense by approximately $25 million and increase our 2011 consolidated effective income tax rate by approximately two percentage points. We expect no remeasurement of our deferred tax assets or liabilities as of December 31, 2010. The impact of these changes is reflected in our balance sheet and results of operations at September 30, 2011.

The change in Israel's fiscal regime may negatively impact our future operations by reducing future project profitability, as compared with profitability under the previous fiscal regime, and potentially reducing the economic attractiveness of exploration activities.

UK   Also in March 2011, the UK government announced that the Finance Bill 2011 will increase the rate of the Supplementary Charge levied on oil and gas income in the UK from 20% to 32% effective March 24, 2011. This change became law on July 19, 2011. We expect the change will increase the tax rate on our UK oil and gas income from 50% to 62%, resulting in an increase of approximately $54 million in our 2011 consolidated income tax expense and an increase in our 2011 consolidated effective income tax rate by approximately four percentage points. The estimated increases in our consolidated income tax expense and effective income tax rate include the impact of remeasuring our UK deferred tax liability as of December 31, 2010 to reflect the higher effective rate. During third quarter 2011, we recorded an increase in both our deferred income tax liability and deferred income tax expense of $34 million. The impact of these changes is reflected in our balance sheet and results of operations at September 30, 2011.

See Item 1. Financial Statements – Note 13. Income Taxes.

Israeli Interministerial Committee   The Israeli Interministerial Committee to Examine Government Policy on Israel's Natural Gas Economy (Interministerial Committee) has been charged with the task of proposing a government policy for developing the natural gas economy in Israel. Objectives include ensuring energy security for the economy, encouraging competition among various sectors in the local economy, and generating economic and political benefits for Israel. Among other things, the Interministerial Committee will examine the best policy for safeguarding reserves to provide for local consumption and for exporting natural gas. The Interministerial Committee is expected to present its recommendations by February 29, 2012. We are monitoring the activities of the Interministerial Committee to assess the possible impact any recommendations could have on our business.

Potential for Future Asset Impairments

The domestic natural gas market remains weak. A decrease in forward natural gas prices for the remainder of 2011 could result in significant impairment charges. Our Piceance basin (western Colorado), Shattuck (western Oklahoma), and Bowdoin (north central Montana) properties have significant natural gas reserves and therefore are sensitive to declines in natural gas prices. These assets, which have a combined net book value of approximately $1.0 billion at September 30, 2011, are at risk of impairment if future NYMEX Henry Hub natural gas prices experience further decline. The cash flow model that we use to assess proved properties for impairment includes numerous assumptions, such as management's estimates of future oil and gas production and commodity prices, market outlook on forward commodity prices, operating and development costs, and discount rates. All inputs to the cash flow model must be evaluated at each date of estimate. However, a decrease in forward natural gas prices alone could result in a significant impairment for our properties that are sensitive to declines in natural gas prices. See Item 1. Financial Statements – Note 4. Asset Impairments.

Risk and Insurance Program

Our business is subject to all of the operating risks normally associated with the exploration, production, gathering, processing and transportation of crude oil and natural gas, including hurricanes, blowouts, well cratering and fire, any of which could result in damage to, or destruction of, oil and natural gas wells or formations or production facilities and other property and injury to persons. As protection against financial loss resulting from many, but not all of these operating hazards, we maintain insurance coverage, including certain physical damage, business interruption (loss of production), employer's liability, comprehensive general liability and worker's compensation insurance. We maintain insurance at levels that we believe are appropriate and consistent with industry practice and we regularly review our potential risks of loss and the cost and availability of insurance and revise our insurance program accordingly.

For example, in certain international locations (including Equatorial Guinea and Israel) we carry business interruption insurance for loss of revenue arising from physical damage to our facilities caused by fire and natural disasters. The coverage is subject to customary deductibles, waiting periods and recovery limits.

In the Gulf of Mexico, we self-insure for windstorm exposure. Our Gulf of Mexico assets are primarily subsea operations; therefore, our windstorm exposure is limited. In addition, the cost of windstorm insurance continues to be very expensive and coverage amounts are limited. We believe it is more cost-effective for us to self-insure these assets. As a result, we are responsible for substantially all windstorm-related damages to our Gulf of Mexico assets.

In accordance with industry practice, oil and gas well owners generally indemnify drilling rig contractors against certain risks, such as those arising from property and environmental losses, pollution from sources such as oil spills, or contamination resulting from well blowout or fire or other uncontrolled flow of hydrocarbons. Most of our domestic and international drilling contracts contain such indemnification clauses. In addition, oil and gas well owners typically assume all costs of well control in the event of an uncontrolled well. We currently carry insurance protection for our net share of any potential financial losses occurring as a result of events such as the Deepwater Horizon Incident. This protection consists of $500 million of well control, pollution cleanup and consequential damages coverage and $326 million of additional pollution cleanup and consequential damages coverage, which also covers third party personal injury and death. Consequently, if we were to experience an accident similar to the Deepwater Horizon Incident, our total insurance for cleanup and consequential damages would cover a gross loss of $826 million, subject to reduction for claims related to well control and third party damages.

We expect the future availability and cost of insurance will be impacted by the Japanese earthquake and subsequent tsunami as well as by the Deepwater Horizon Incident. Impacts could include tighter underwriting standards, limitations on scope and amount of coverage, and higher premiums, and will depend, in part, on future changes in laws and regulations regarding exploration and production activities in the Gulf of Mexico, including possible increases in liability caps for claims of damages from oil spills. We anticipate that current changes in the types of coverage available in the insurance market will result in lower effective coverages and/or the incurrence of higher premiums to achieve past levels of coverage.

During 2010, various Congressional committees began pursuing legislation to increase or remove liability caps for deepwater drilling. The current $75 million liability limit under the Oil Pollution Act may be materially increased or lifted in its entirety. Such a requirement would ultimately require a company to maintain either a much higher level of insurance coverage than was standard for the industry in the past, or a financial position large enough that a company could settle its own damage claims. We anticipate that, at a minimum, less insurance coverage will be available and at a higher cost. We continue to monitor the legislative and regulatory response to the Deepwater Horizon Incident and its impact on the insurance market and our overall risk profile. Accordingly, we may adjust our risk and insurance program to provide protection at insured levels that reflect our perception of the cost of risk relative to frequency and severity of the exposure.

Deepwater drilling entails inherent risks. We have a risk assessment program that analyzes safety and environmental hazards and establishes procedures, work practices, training programs and equipment requirements, including monitoring and maintenance rules, for continuous improvement. We have a strong safety performance record and continue to manage our risks and operations such that the likelihood of a significant accident or spill is remote. However, if an event occurs that is not covered by insurance or not fully protected by insured limits, it could have a material adverse impact on our results of operations, cash flows and financial condition.

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Oil Spill Response Preparedness

We maintain membership in Clean Gulf Associates (CGA), a nonprofit association of production and pipeline companies operating in the Gulf of Mexico. On behalf of its membership, CGA has contracted with Helix Energy Solutions Group (HESG) for the provision of subsea intervention, containment, capture and shut-in capacity for deepwater Gulf of Mexico exploration wells. The system, known as the Helix Fast Response System (HFRS), at full production capacity, can process up to 55 MBbl/d of oil, 70 MBbl/d of liquids and 95 MMcf/d of natural gas, at 10,000 pounds per square inch (psi) in water depths to 10,000 feet. The containment resources also include a 15,000 psi-gauge intervention capping stack designed to handle extremely high-pressure, deeper wells in the deepwater Gulf of Mexico. We have entered into a separate utilization agreement with HESG which specifies the asset day rates should the HFRS system be deployed.

Recently Issued Accounting Standards Update

See Item 1. Financial Statements – Note 2. Basis of Presentation.

RESULTS OF OPERATIONS

Revenues

Revenues were as follows:

(millions)		2011		2010	Increase from Prior Year	
Three Months Ended September 30, 2011						
Oil, Gas and NGL Sales	$	874	$	704	24	%
Income from Equity Method Investees		50		34	47	%
Other Revenues		-		17	(100	%)
Total	$	924	$	755	22	%
Nine Months Ended September 30, 2011						
Oil, Gas and NGL Sales	$	2,599	$	2,102	24	%
Income from Equity Method Investees		146		85	72	%
Other Revenues		33		52	(37	%)
Total	$	2,778	$	2,239	24	%

Changes in revenues are discussed below.

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Oil, Gas and NGL Sales Average daily sales volumes and average realized sales prices were as follows:

	Sales Volumes				Average Realized Sales Prices		
	Crude Oil & Condensate (MBbl/d)	Natural Gas (MMcf/d)	NGLs (MBbl/d)	Total (MBoe/d) (1)	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)	NGLs (Per Bbl)
Three Months Ended September 30, 2011							
United States	38	358	16	113	$91.21	$3.98	$49.57
Equatorial Guinea (2)	15	250	-	57	108.11	0.27	-
Israel	-	228	-	38	-	5.15	-
North Sea	4	4	-	5	115.67	8.41	-
China	4	-	-	4	108.57	-	-
Total Consolidated Operations	61	840	16	217	98.15	3.21	49.57
Equity Investees (3)	2	-	5	7	107.90	-	72.70
Total Operations	63	840	21	224	$98.43	$3.21	$55.74
Three Months Ended September 30, 2010							
United States (4)	41	399	13	120	$71.28	$3.87	$36.30
Equatorial Guinea (2)	8	243	-	49	76.28	0.27	-
Israel	-	178	-	30	-	3.85	-
North Sea	13	6	-	14	78.89	5.82	-
Ecuador (5)	-	28	-	5	-	-	-
China	4	-	-	4	71.37	-	-
Total Consolidated Operations	66	854	13	222	73.41	2.82	36.30
Equity Investees (3)	2	-	6	8	77.03	-	50.83
Total Operations	68	854	19	230	$73.53	$2.82	$40.77
Nine Months Ended September 30, 2011							
United States	37	373	14	114	$95.10	$4.09	$49.19
Equatorial Guinea (2)	13	244	-	54	108.40	0.27	-
Israel	-	180	-	30	-	4.80	-
North Sea	8	6	-	9	112.99	7.90	-
China	4	-	-	4	104.99	-	-
Total Consolidated Operations	62	803	14	211	100.86	3.12	49.19
	2	-	5	7	109.20	-	74.70

Equity Investees (3)							
Total Operations	64	803	19	218	$101.09	$3.12	$55.95
Nine Months Ended September 30, 2010							
United States (4)	40	399	13	119	$73.31	$4.38	$40.17
Equatorial Guinea (2)	11	221	-	48	75.44	0.27	-
Israel	-	129	-	22	-	4.08	-
North Sea	10	7	-	11	77.33	5.25	-
Ecuador (5)	-	28	-	4	-	-	-
China	4	-	-	4	73.27	-	-
Total Consolidated Operations	65	784	13	208	74.30	3.13	40.17
Equity Investees (3)	2	-	5	7	75.84	-	52.04
Total Operations	67	784	18	215	$74.35	$3.13	$43.58

(1) Natural gas is converted on the basis of six Mcf of gas per one barrel of oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency. Given commodity price differentials, the price for a barrel of oil equivalent for natural gas is significantly less than the price for a barrel of oil.

(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 methanol and LPG plants are owned by affiliated entities accounted for under the equity method of accounting.

(3) Volumes represent sales of condensate and LPG from the Alba plant in Equatorial Guinea. See Income from Equity Method Investees below.

(4) Average realized crude oil and condensate prices reflect reductions of $1.25 per Bbl for third quarter 2010 and $1.31 per Bbl for the first nine months of 2010 from hedging activities.

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Average realized natural gas prices reflect a reduction of $0.01 per Mcf for the first nine months of 2010 from hedging activities. The average realized natural gas price for the third quarter of 2010 was not impacted by hedging activities, as the net deferred amounts reclassified from AOCL were de minimis.

The price reductions resulted from hedge gains/losses that were previously deferred in AOCL. All hedge gains or losses had been reclassified to revenues by December 31, 2010.

(5) Our Block 3 PSC was terminated by the Ecuadorian government on November 25, 2010. Intercompany natural gas sales for 2010 were eliminated for accounting purposes. Electricity sales (through May 2011) are included in other revenues. See Item 1. Financial Statements – Note 2. Basis of Presentation and Note 3. Acquisitions and Divestitures.

If the realized gains and losses on commodity derivative instruments, which are included in (gain) loss on commodity derivative instruments in our consolidated statements of operations, had been included in oil and gas revenues, the effect on average realized prices would have been as follows:

	Commodity Price Increase (Decrease)			
	2011		2010	
	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)
Three Months Ended September 30,				
United States	$ (1.23)	.79	$ 0.86	$ 0.87
Equatorial Guinea	-	-	(2.09)	-
Total Consolidated Operations	(.77)	.34	0.27	0.41
Total Operations	(.74)	.34	0.26	0.41
Nine Months Ended September 30,				
United States	$ (3.52)	.74	$ 0.16	$ 0.63
Equatorial Guinea	-	-	(1.86)	-
Total Consolidated Operations	(2.10)	.34	(0.22)	0.32
Total Operations	(2.04)	.34	(0.21)	0.32

An analysis of revenues from sales of crude oil, natural gas and NGLs is as follows:

	Sales Revenues			
	Crude Oil & Condensate	Natural Gas	NGLs	Total
(millions)				
Three Months Ended September, 2010	$ 446	$ 214	$ 44	$ 704
Changes due to				
Increase (Decrease) in Sales Volumes	(30)	4	8	(18)
Increase in Sales Prices Before Hedging	134	31	18	183
Change in Amounts Reclassified from AOCL	5	-	-	5
Three Months Ended September 30, 2011	$ 555	$ 249	$ 70	$ 874
Nine Months Ended September 30, 2010	$ 1,313	$ 646	$ 143	$ 2,102
Changes due to				
Increase (Decrease) in Sales Volumes	(46)	40	17	11

Increase (Decrease) in Sales Prices Before Hedging		439		(4)		36		471
Change in Amounts Reclassified from AOCL		14		1		-		15
Niine Months Ended September 30, 2011	$	1,720	$	683	$	196	$	2,599

Crude oil and condensate sales – Revenues from crude oil and condensate sales increased during the third quarter and first nine months of 2011 as compared with 2010 due to the following:

- increases in average realized prices;
- higher sales volumes in the DJ Basin attributable to the continued acceleration of our vertical and horizontal drilling programs in Wattenberg;
- higher sales volumes attributable to the Central DJ Basin asset acquisition that closed in March 2010; and
- higher sales volumes in Equatorial Guinea due to a higher number of liftings;

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partially offset by:

- decreases in sales volumes from the Gulf Coast and Mid-Continent areas due to natural field decline;
- a decrease in onshore US volumes due to the sale of certain Oklahoma and Illinois Basin assets in 2010; and
- a decrease in North Sea volumes due to downtime in the Dumbarton field for FPSO maintenance.

Revenues from crude oil and condensate sales included deferred losses of $5 million for the third quarter of 2010 and $14 million for the first nine months of 2010 reclassified from AOCL related to commodity derivative instruments previously accounted for as cash flow hedges. As of December 31, 2010, there were no further amounts related to commodity derivative instruments remaining to be reclassified from AOCL to crude oil revenues.

Natural gas sales – Revenues from natural gas sales increased during the third quarter and first nine months of 2011 as compared with 2010 due to the following:

- higher natural gas prices during third quarter 2011 primarily due to increases in sales prices in Israel which benefit from strong global liquids markets;
- an increase in Israel sales volumes due to an increase in demand for our natural gas driven by higher electricity production and lower levels of competitor natural gas imports from Egypt;
- higher sales volumes in the DJ Basin attributable to the continued acceleration of our vertical and horizontal drilling programs in the Wattenberg area ;
- higher sales volumes attributable to the Central DJ Basin asset acquisition that closed in March 2010; and
- higher sales volumes in Equatorial Guinea as compared with the first nine months of 2010, during which time the Alba field experienced a planned shut-down for facilities maintenance and repair;

partially offset by:

- a decrease in onshore US sales volumes due to the sale of certain Oklahoma and Illinois Basin assets in 2010; and
- decreases in sales volumes from the deepwater Gulf of Mexico, Gulf Coast and Mid-Continent areas due to natural field decline.

Revenues from natural gas sales included a deferred loss of $1 million for the first nine months of 2010 reclassified from AOCL related to commodity derivative instruments previously accounted for as cash flow hedges. Revenues for the third quarter of 2010 included de minimis amounts reclassified from AOCL. As of December 31, 2010, there were no further amounts related to commodity derivative instruments remaining to be reclassified from AOCL to natural gas revenues.

NGL sales – Most of our US NGL production is from the Wattenberg area and deepwater Gulf of Mexico. NGL sales revenues increased during the third quarter and first nine months of 2011 as compared with 2010 due to higher realized prices and a slight increase in sales volumes due to ongoing development activity in the Wattenberg area.

Income from Equity Method Investees We have a 45% interest in Atlantic Methanol Production Company, LLC, which owns and operates a methanol plant and related facilities and a 28% interest in Alba Plant LLC, which owns and operates a liquefied petroleum gas processing plant. Both plants are located onshore on Bioko Island in Equatorial Guinea. Equity method investments are included in other noncurrent assets in our consolidated balance sheets, our share of earnings is reported as income from equity method investees in our consolidated statements of operations, and our share of dividends is reported within cash flows from operating activities in our consolidated statements of cash flows.

The increase in income from equity method investees for the third quarter and first nine months of 2011 as compared with 2010 was due to increases in average realized condensate, LPG and methanol prices due to global economic recovery, and increases in methanol sales volumes. Condensate and LPG sales volumes and average realized prices are included in the average daily sales volumes and average realized sales prices table above.

Methanol sales volumes and prices were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Methanol Sales Volumes (Mmgal)	41	33	119	102
Methanol Sales Prices (per gallon)	$ 1.08	$ 0.84	$ 1.04	$ 0.84

Other Revenues   Other revenues include electricity sales and other revenues from operating activities. See Item 1. Financial Statements – Note 2. Basis of Presentation.

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Operating Costs and Expenses

Operating costs and expenses were as follows:

(millions)	2011	2010	Increase (Decrease) from Prior Year
Three Months Ended September 30,			
Production Expense	$ 153	$ 141	9 %
Exploration Expense	57	35	63 %
Depreciation, Depletion and Amortization	225	231	(3 %)
General and Administrative	89	65	37 %
Gain on Divestitures	-	(114)	(100 %)
Asset Impairments	-	100	(100 %)
Other Operating (Income) Expense, Net	2	4	(50 %)
Total	$ 526	$ 462	14 %
Nine Months Ended September 30,			
Production Expense	$ 449	$ 430	4 %
Exploration Expense	195	167	17 %
Depreciation, Depletion and Amortization	681	662	3 %
General and Administrative	254	194	31 %
Gain on Divestitures	(26)	(114)	(77 %)
Asset Impairments	139	100	39 %
Other Operating (Income) Expense, Net	45	59	(24 %)
Total	$ 1,737	$ 1,498	16 %

Changes in operating costs and expenses are discussed below.

Production Expense   Components of production expense were as follows:

(millions, except unit rate)	Total per BOE (1)	Total	United States	Equatorial Guinea	Israel	North Sea	Other Int'l, Corporate
Three Months Ended September 30, 2011							
Lease Operating Expense (2)	$4.89	$98	$66	$ 12	$2	$10	$8
Production and Ad Valorem Taxes	1.92	38	25	-	-	-	13
Transportation Expense	0.88	17	15	-	-	2	-
Total Production Expense	$7.69	$153	$106	$ 12	$2	$12	$21
Three Months Ended September 30, 2010							
	$4.65	$95	$60	$ 11	$2	$16	$6

Lease Operating Expense (2)							
Production and Ad Valorem Taxes	1.40	29	24	-	-	-	5
Transportation Expense	0.84	17	14	-	-	2	1
Total Production Expense	$6.89	$141	$98	$ 11	$2	$18	$12
Nine Months Ended September 30, 2011							
Lease Operating Expense (2)	$5.00	$288	$188	$ 35	$9	$38	$18
Production and Ad Valorem Taxes	1.87	108	77	-	-	-	31
Transportation Expense	0.92	53	45	-	-	6	2
Total Production Expense	$7.79	$449	$310	$ 35	$9	$44	$51
Nine Months Ended September 30, 2010							
Lease Operating Expense (2)	$4.97	$283	$193	$ 31	$7	$38	$14
Production and Ad Valorem Taxes	1.69	96	80	-	-	-	16
Transportation Expense	0.90	51	44	-	-	5	2
Total Production Expense	$7.56	$430	$317	$ 31	$7	$43	$32

(1) Consolidated unit rates exclude sales volumes and expenses attributable to equity method investees.

(2) Lease operating expense includes oil and gas operating costs (labor, fuel, repairs, replacements, saltwater disposal and other related lifting costs) and workover expense.

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For the third quarter and first nine months of 2011, total production expense increased as compared with 2010 due to the following:

- an increase in US lease operating expense due to higher sales volumes from the Wattenberg area due to ongoing development activities;
- increases in Equatorial Guinea and Israel lease operating expense due to higher sales volumes, as discussed above; and
- an increase in China production taxes due to higher commodity prices;

partially offset by:

- a decrease in US lease operating expense due to the sale of certain Oklahoma and Illinois Basin assets in 2010; and
- a decrease in US production taxes due to lower crude oil sales volumes related to the sale of certain Oklahoma assets in 2010 and natural field decline in the Gulf Coast and Mid-Continent areas.

Oil and Gas Exploration Expense Components of oil and gas exploration expense were as follows:

(millions)	Total	United States	West Africa (1)	Eastern Mediter-ranean (2)	North Sea	Other Int'l, Corporate (3)
Three Months Ended September 30, 2011						
Dry Hole Cost	$ 13	$ -	$ 13	$ -	$ -	$ -
Seismic	8	5	-	-	-	3
Exploration Expense	33	14	1	1	1	16
Other	3	3	-	-	-	-
Total Exploration Expense	$ 57	$ 22	$ 14	$ 1	$ 1	$ 19
Three Months Ended September 30, 2010						
Dry Hole Cost	$ 2	$ 1	$ -	$ -	$ -	$ 1
Seismic	17	4	-	4	-	9
Exploration Expense	12	(4)	1	1	1	13
Other	4	4	-	-	-	-
Total Exploration Expense	$ 35	$ 5	$ 1	$ 5	$ 1	$ 23
Nine Months Ended September 30, 2011						
Dry Hole Cost	$ 57	$ 20	$ 37	$ -	$ -	$ -
Seismic	47	28	1	3	-	15
Exploration Expense	77	26	4	1	2	44
Other	14	14	-	-	-	-
Total Exploration Expense	$ 195	$ 88	$ 42	$ 4	$ 2	$ 59
Nine Months Ended September 30, 2010						
Dry Hole Cost	$ 57	$ 53	$ 3	$ -	$ -	$ 1
Seismic	52	32	5	6	-	9
Exploration Expense	46	4	4	2	2	34
Other	12	12	-	-	-	-

Total Exploration Expense	$ 167	$ 101	$ 12	$ 8	$ 2	$ 44

(1) West Africa includes Equatorial Guinea, Cameroon, Senegal and Guinea-Bissau.
(2) Eastern Mediterranean includes Israel and Cyprus.
(3) Other International includes China and various international new ventures such as offshore Nicaragua and offshore France.

Oil and gas exploration expense for the third quarter and first nine months of 2011 included the following:

- dry hole cost associated with exploratory drilling in the US Rocky Mountain area and offshore Senegal and Guinea-Bissau;
- acquisition of seismic information for Wattenberg, Rocky Mountain and deepwater Gulf of Mexico areas in the US, offshore Nicaragua, offshore France, and offshore Cyprus; and
- staff expense associated with new ventures offshore Nicaragua and offshore France.

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Oil and gas exploration expense for the third quarter and first nine months of 2010 included the following:

- US dry hole cost associated with the Double Mountain exploration well in the deepwater Gulf of Mexico;
- acquisition of seismic information in the US in support of Central Gulf of Mexico lease sales and in West Africa for Cameroon;
- and staff expense associated with new ventures.

Depreciation, Depletion and Amortization   DD&A expense was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
DD&A Expense (millions) (1)	$ 225	$ 231	$ 681	$ 662
Unit Rate per BOE (2)	$ 11.30	$ 11.35	$ 11.84	$ 11.64

(1) For DD&A expense by geographical area, see Item 1. Financial Statements – Note 15. Segment Information.

(2) Consolidated unit rates exclude sales volumes and expenses attributable to equity method investees.

Total DD&A expense for the first nine months of 2011 increased as compared with 2010 due to the following:

- higher DD&A expense in the Wattenberg area of our onshore US operations due to higher sales volumes resulting from ongoing capital spending;
- higher DD&A expense in Equatorial Guinea due to higher sales volumes; and
- higher DD&A expense in China due to higher costs associated with development activities;

partially offset by:

- lower DD&A expense in the deepwater Gulf of Mexico, Gulf Coast, and Mid-Continent areas of our US operations due to lower sales volumes resulting from natural field decline; and
- the cessation of DD&A associated with certain Oklahoma and Illinois Basin assets sold during 2010.

Changes in the unit rate per BOE for the third quarter and first nine months of 2011 as compared with 2010 were due to changes in the mix of production. For example, sales volumes from Equatorial Guinea and Israel have lower DD&A rates.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
G&A Expense (millions)	$ 89	$ 65	$ 254	$ 194
Unit Rate per BOE (1)	$ 4.45	$ 3.20	$ 4.41	$ 3.42

(1) Consolidated unit rates exclude sales volumes and expenses attributable to equity method investees.

G&A expense for the third quarter and first nine months of 2011 increased as compared with 2010 primarily due to additional expenses relating to personnel, office, and information technology costs in support of our major development projects and increased exploration activities.

Gain on Divestitures Gain on divestitures was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
(millions)				
Gain on Divestitures	$ -	$ (114)	$ (26)	$ (114)

See Item 1. Financial Statements – Note 3. Acquisitions and Divestitures.

Asset Impairments Asset impairment expense was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
(millions)				
Asset Impairments	$ -	$ 100	$ 139	$ 100

See Item 1. Financial Statements – Note 4. Asset Impairments and Note 7. Fair Value Measurements and Disclosures.

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Other Operating (Income) Expense, Net Other operating (income) expense, net was as follows:

(millions)	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Deepwater Gulf of Mexico Moratorium Expense	$ (1)	$ -	$ 18	$ 27
Electricity Generation Expense	-	9	26	26
Loss on Involuntary Conversion	-	-	4	-
Other, Net	3	(5)	(3)	6
Total	$ 2	$ 4	$ 45	$ 59

See Item 1. Financial Statements – Note 2. Basis of Presentation.

Other (Income) Expense

Other (income) expense was as follows:

(millions)	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Gain on Commodity Derivative Instruments	$ (322)	$ (38)	$ (179)	$ (280)
Interest, Net of Amount Capitalized	14	21	51	60
Other Non-Operating (Income) Expense, Net	(16)	12	(16)	(1)
Total	$ (324)	$ (5)	$ (144)	$ (221)

Gain on Commodity Derivative Instruments Gain on commodity derivative instruments is a result of mark-to-market accounting. See Item 1. Financial Statements – Note 6. Derivative Instruments and Hedging Activities and Note 7. Fair Value Measurements and Disclosures.

Interest Expense and Capitalized Interest Interest expense and capitalized interest were as follows:

(millions, except unit rate)	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Interest Expense	$ 48	$ 36	$ 138	$ 105
Capitalized Interest	(34)	(15)	(87)	(45)
Interest Expense, Net	$ 14	$ 21	$ 51	$ 60
Unit Rate per BOE (1)	$ 0.69	$ 1.02	$ 0.89	$ 1.05

(1) Consolidated unit rates exclude sales volumes and expenses attributable to equity method investees.

Interest expense increased for the third quarter and first nine months of 2011 as compared with 2010. The increase in interest expense resulted from a higher outstanding debt balance during the period and the interest associated with our 6% senior unsecured notes issued in first quarter 2011. The higher rate on the senior unsecured notes replaced the substantially lower rate applicable to our revolving credit facility which was repaid with proceeds from our debt offering. See also Liquidity and Capital Resources – Financing Activities below.

The increase in the amount of interest capitalized is due to higher work in progress amounts related to major long-term projects in the deepwater Gulf of Mexico, West Africa, and Israel and a higher weighted average interest rate associated with our 6% senior unsecured notes, which impacted the average rate we pay on long-term debt.

Other Non-operating (Income) Expense, Net   Other non-operating (income) expense, net includes deferred compensation (income) expense, interest income and other (income) expense. See Item 1. Financial Statements – Note 2. Basis of Presentation.

Income Tax Provision

See Current Global Economic Situation, Changes in Fiscal Regimes and Market Regulations, above, and Item 1. Financial Statements – Note 13. Income Taxes for a discussion of the change in our effective tax rate for the first nine months of 2011 as compared with 2010.

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LIQUIDITY AND CAPITAL RESOURCES

Capital Structure/Financing Strategy

In seeking to effectively fund and monetize our major development projects, we employ a capital structure and financing strategy designed to provide ample liquidity throughout the commodity price cycle. Specifically, we strive to retain the ability to fund long cycle, multi-year, capital intensive development projects while also maintaining the capability to execute a robust exploration program and financially attractive periodic mergers and acquisitions activity. We endeavor to maintain an investment grade debt rating in service of these objectives. We also utilize a commodity price hedging program to reduce commodity price uncertainty and enhance the predictability of cash flows along with a risk and insurance program to protect against disruption to our cash flows and operations.

Traditional sources of our liquidity are cash on hand, cash flows from operations and available borrowing capacity under our credit facility. Occasional sales of non-strategic crude oil and natural gas properties as well as our periodic access to capital markets may also generate cash.

Our financial capacity, coupled with our balanced and diversified portfolio, provides us with flexibility in our investment decisions including execution of our major development projects and increased exploration activity.

Marcellus Shale Joint Venture On September 30, 2011 we closed a joint venture partnership arrangement with a subsidiary of CONSOL Energy, Inc. See Item 1. Financial Statements – Note 3. Acquisitions and Divestitures and Note 5. Debt.

The transaction is structured in a unique way from a financial perspective. We have spread the payment over a three-year period, beginning at closing. The $2.1 billion CONSOL Carried Cost Obligation is expected to extend over an eight-year period and is capped at $400 million in each calendar year and will be suspended if average Henry Hub natural gas prices fall and remain below $4.00 per MMBtu in any three consecutive month period and will remain suspended until average Henry Hub natural gas prices are above $4.00 per MMBtu for three consecutive months. These conditions allow us to integrate a new core area into our existing long range plan while maintaining our strong balance sheet and financial flexibility. We funded the initial cash payment with cash on hand and borrowings under our credit facility and expect to fund the remaining installment payments and CONSOL Carried Cost Obligation with cash on hand and our credit facility. Targeted divestments of non-core assets may also be a source of funding.

Available Liquidity Information regarding cash and debt balances was as follows:

	September 30, 2011		December 31, 2010	
(millions, except percentages)				
Cash and Cash Equivalents	$ 1,252		$ 1,081	
Amount Available to be Borrowed Under Credit Facility (1)	1,700		1,750	
Total Liquidity	$ 2,952		$ 2,831	
Total Debt (2)	$ 3,891		$ 2,279	
Total Shareholders' Equity	7,582		6,848	
Ratio of Debt-to-Book Capital (3)	34	%	25	%

(1) See Credit Facility below.

(2)

Total debt includes FPSO lease obligation and remaining CONSOL installment payments and excludes unamortized debt discount.

(3) We define our ratio of debt-to-book capital as total debt (which includes long-term debt excluding unamortized discount, the current portion of long-term debt, and short-term borrowings) divided by the sum of total debt plus shareholders' equity.

Cash and Cash Equivalents   We had approximately $1.25 billion in cash and cash equivalents at September 30, 2011, primarily denominated in US dollars and invested in money market funds and short-term deposits with major financial institutions. Approximately $986 million of this cash is attributable to our foreign subsidiaries. We currently intend to use our international cash to fund international programs, including the planned developments in Equatorial Guinea and Israel. At September 30, 2011, we believe that sufficient liquidity is available in the US to fund our planned domestic programs. We currently do not expect to need additional foreign funds for US working capital or investment purposes. However, we have the ability to repatriate additional funds if we desire to do so. Any foreign cash repatriated would likely be subject to additional US income taxes and could result in an increase in our tax liability, after considering available foreign tax credits and/or other tax attributes.

Credit Facility   At September 30, 2011, we had an unsecured revolving credit facility that was due to mature December 9, 2012. The commitment was $2.1 billion until December 9, 2011, at which time the commitment would reduce to $1.8 billion. We borrowed $400 million under the credit facility in order to finance the Marcellus shale property acquisitions, and ended third quarter 2011 with $1.7 billion remaining available for borrowing. On October 14, 2011, we terminated the existing $2.1 billion credit facility and entered into a Credit Agreement which provides for a new $3.0 billion unsecured revolving credit facility due October 14, 2016. See Financing Activities New Credit Facility below.

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Derivative Instruments We use various derivative instruments in connection with anticipated crude oil and natural gas sales to minimize the impact of product price fluctuations and ensure cash flow for future capital needs. Such instruments include variable to fixed price commodity swaps, two and three-way collars and basis swaps. Current period settlements on commodity derivative instruments impact our liquidity, since we are either paying cash to, or receiving cash from, our counterparties. If actual commodity prices are higher than the fixed or ceiling prices in our derivative instruments, our cash flows will be lower than if we had no derivative instruments. Conversely, if actual commodity prices are lower than the fixed or floor prices in our derivative instruments, our cash flows will be higher than if we had no derivative instruments. None of our counterparty agreements contain margin requirements. We also use derivative instruments to manage interest rate risk by entering into forward contracts or swap agreements to minimize the impact of interest rate fluctuations associated with fixed or floating rate borrowings.

Commodity derivative instruments are recorded at fair value in our consolidated balance sheets, and changes in fair value are recorded in earnings in the period in which the change occurs. As of September 30, 2011 the fair value of our commodity derivative assets was $131 million and the fair value of our commodity derivative liabilities was $6 million (after consideration of netting agreements). See Item 1. Financial Statements – Note 6. Derivative Instruments and Hedging Activities for a discussion of counterparty credit risk and Note 7. Fair Value Measurements and Disclosures for a description of the methods we use to estimate the fair values of derivative instruments.

Insurance Recoveries In May 2011, we ended drilling operations at the Leviathan-2 appraisal well location offshore Israel. The incident was a covered event under our well control insurance. At this time, we expect to recover most of the costs from insurance, subject to a deductible. We do not expect any delays in the insurance claim recovery process to have a significant impact on our cash flows or liquidity. See Item 1. Financial Statements – Note 2. Basis of Presentation and Leviathan-2 Insurance Recoveries, above.

Contractual Obligations

The following table updates certain contractual obligations from amounts reported in our Annual Report on Form 10-K for the year ended December 31, 2010. Unless otherwise noted, all amounts are net to our interest:

Obligation (millions)	Total	2011	2012 and 2013	2014 and 2015	2016 and beyond
Long-Term Debt (Excluding Interest) (1)	$ 3,540	$ -	$ 1,056	$ 200	$ 2,284
Cash Payments for Interest (2)	3,091	19	374	339	2,359
CONE Gathering LLC MARC (3)	26	3	23	-	-
FPSO Lease Payments (4)	496	12	144	142	198

(1) Long-term debt excludes our FPSO lease obligation. See Item 1. Financial Statements – Note 5. Debt.
(2) Cash payments for interest are based on the total debt balance, scheduled maturities and interest rates in effect at September 30, 2011.
(3) Represents minimum annual revenue commitments. See Item 1. Financial Statements – Note 3. Acquisitions and Divestitures.
(4) The FPSO arrived at the Aseng field offshore Equatorial Guinea on October 16, 2011. Annual lease payments, net to our interest, exclude regular maintenance and operational costs, and will begin when the FPSO initiates producing operations. These payments are also subject to change based on change orders implemented during the construction period, final accounting treatment, and other factors. See Item 1. Financial Statements – Note 5. Debt.

CONSOL Carried Cost Obligation The CONSOL Carried Cost Obligation represents our agreement to fund up to approximately $2.1 billion of CONSOL's future drilling and completion costs. The CONSOL Carried Cost Obligation is expected to extend over an eight-year period. It is capped at $400 million in each calendar year and will be suspended if average Henry Hub natural gas prices fall and remain below $4.00 per MMBtu in any three consecutive month period and will remain suspended until average Henry Hub natural gas prices are above $4.00 per MMBtu for three consecutive months. Therefore, specific payment dates for the funding of the CONSOL Carried Cost Obligation cannot be determined at this time. See Item 1. Financial Statements – Note 3. Acquisitions and Divestitures and Note 5. Debt.

Cash Flows

Cash flow information is as follows:

(millions)	Nine Months Ended September 30, 2011	2010
Total Cash Provided By (Used in)		
Operating Activities	$ 1,785	$ 1,452
Investing Activities	(2,383)	(1,232)
Financing Activities	769	(85)
Increase in Cash and Cash Equivalents	$ 171	$ 135

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Operating Activities   Net cash provided by operating activities for the first nine months of 2011 increased as compared with 2010 primarily due to higher revenues, which benefitted from increases in commodity prices. The increase in cash flow was partially offset by increases in general and administrative expense and interest expense. See Item 1. Financial Statements – Consolidated Statements of Cash Flows.

Investing Activities   Our investing activities include capital spending on a cash basis for oil and gas properties and investments in unconsolidated subsidiaries accounted for by the equity method. These investing activities may be offset by proceeds from property sales or dispositions. Capital spending for property, plant and equipment increased by $542 million during the first nine months of 2011 as compared with 2010, primarily due to our increased major project development activity in the Wattenberg area, offshore West Africa, and offshore Israel. We also made an initial investment of $519 in Marcellus shale assets and $73 million in CONE Gathering LLC. Investing activities were offset by $77 million proceeds from divestitures of non-core assets including our Ecuador assets and certain onshore US assets. Additional investing activities for 2010 included $458 million related to the Central DJ Basin asset acquisition, offset by proceeds of $552 million from the sale of non-core onshore US assets.

Financing Activities   Our financing activities include the issuance or repurchase of our common stock, payment of cash dividends on our common stock, the borrowing of cash and the repayment of borrowings. During the first nine months of 2011, funds were provided by net cash proceeds from borrowings under our revolving credit facility ($520 million) and the issuance of 6% senior notes ($836 million). Funds were also provided by cash proceeds from, and tax benefits related to, the exercise of stock options ($43 million). We used a portion of the proceeds from the issuance of senior notes to repay amounts outstanding under our credit facility ($470 million). We also used cash to settle an interest rate lock ($40 million), pay dividends on our common stock ($104 million) and repurchase shares of our common stock ($16 million).

In comparison, during the first nine months of 2010, $32 million of funds were provided by net increases in borrowings under our revolving credit facility and used to fund the Central DJ Basin asset acquisition and other capital expenditures. Funds were also provided by cash proceeds from, and tax benefits related to, the exercise of stock options ($54 million). We used cash to pay dividends on our common stock ($95 million) and repurchase shares of our common stock ($12 million).

See Item 1. Financial Statements – Consolidated Statements of Cash Flows.

Investing Activities

Acquisition, Capital and Exploration Expenditures   Information for investing activities (on an accrual basis) is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions)	2011	2010	2011	2010
Acquisition, Capital and Exploration Expenditures				
Unproved Property Acquisition	$ 826	$ 86	$ 883	$ 294
Proved Property Acquisition	370	(11)	370	352
Exploration (1)	58	51	286	222
Development	604	459	1,478	1,096
Corporate and Other	40	23	128	81
Total	$ 1,898	$ 608	$ 3,145	$ 2,045

Other				
Investment in Equity Method Investee	$ 73	$ -	$ 73	$ -
Increase in FPSO Lease Obligation	5	80	56	188

(1) Amount for three and nine months ended September 30, 2011 is net of probable insurance proceeds totaling $25 million related to our Leviathan -2 appraisal well offshore Israel.

2011 Unproved property acquisition costs include $790 million related to our acquisition of a 50% interest in Marcellus shale undeveloped leases, $40 million related to our position offshore Senegal and Guinea-Bissau (the AGC Profond block), and miscellaneous onshore US lease acquisitions. Proved property acquisition costs include $370 million related to the Marcellus shale. The increase in development costs is due to increased capital spending on major development projects located in the DJ Basin, offshore Equatorial Guinea and offshore Israel.

In connection with the Marcellus shale joint venture, we acquired a 50% interest in CONE Gathering Company LLC for $73 million in cash. CONE Gathering LLC was formed for the purpose of owning and operating the existing gathering assets and constructing, owning and operating all of the additional gathering lines and related facilities that will be needed during the course of the Marcellus shale development and will be accounted for using the equity method.

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See Item 1. Financial Statements – Note 3. Acquisitions and Divestitures.

2010 Unproved property acquisition costs included $38 million for lease bonuses paid on deepwater Gulf of Mexico lease blocks, $146 million related to the Central DJ Basin asset acquisition, and the remainder primarily for other onshore US lease acquisitions. Proved property acquisition costs related to the Central DJ Basin asset acquisition.

FPSO Lease Obligation The FPSO lease obligation represents the increase in construction costs to date on the Aseng FPSO to be used in the development of the Aseng field in Equatorial Guinea. See Item 1. Financial Statements – Note 5. Debt.

Financing Activities

New Credit Facility On October 14, 2011, we entered into a Credit Agreement which provides for a new $3.0 billion unsecured revolving credit facility (the New Credit Facility). The New Credit Facility replaces our $2.1 billion credit facility maturing December 9, 2012.

The New Credit Facility (i) provides for an initial commitment of $3.0 billion with an option to increase the overall commitment amount by up to an additional $1.0 billion, subject to the consent of any increasing lenders, (ii) will mature on October 14, 2016, (iii) provides for facility fee rates that range from 12.5 basis points to 30 basis points per year depending upon our credit rating, (iv) includes sub-facilities for short-term loans and letters of credit up to an aggregate amount of $500 million under each sub-facility and (iv) provides for interest rates that are based upon the Eurodollar rate plus a margin that ranges from 100 basis points to 145 basis points depending upon our credit rating.

Also on October 14, 2011, we drew down $400 million under the New Credit Facility, the proceeds of which were utilized to repay outstanding borrowings under and to terminate our existing $2.1 billion credit facility maturing December 9, 2012. After the draw down, $2.6 billion remained available for borrowing under the New Credit Facility.

See Item 1. Financial Statements – Note 5. Debt.

CONSOL Installment Payments On September 30, 2011, we closed an agreement with CONSOL under which we agreed to purchase a 50% interest in undeveloped Marcellus shale acreage. In addition to the cash paid at closing, we agreed to make two additional installment payments of $328 million each on September 30, 2012 and 2013. The installment payments have been discounted at the prevailing market rates for similar debt instruments, a weighted average of 1.76%. See Item 1. Financial Statements – Note 3. Acquisitions and Divestitures and Note 5. Debt.

Public Debt Offering In order to provide increased liquidity and lengthen our weighted average debt maturity, on February 18, 2011, we completed an underwritten public offering of $850 million of 6% senior unsecured notes due March 1, 2041, receiving net proceeds of $836 million after deducting discount and underwriting fees. Approximately $470 million of the net proceeds were used to repay outstanding indebtedness under our revolving credit facility maturing 2012 and the balance of the proceeds will be used for general corporate purposes.

Fixed-Rate Debt Our outstanding fixed-rate debt, including the remaining CONSOL installment payments, totaled approximately $3.1 billion at September 30, 2011. The weighted average interest rate on fixed-rate debt was 6.01%, with maturities ranging from 2012 to 2097. Approximately 17% of our fixed rate debt matures within the next five years.

FPSO Lease Obligation We have an agreement for the construction and lease of an FPSO to be used for development of the Aseng field, offshore Equatorial Guinea. The FPSO is currently being installed at the Aseng field, and we are including the FPSO lease obligation in our balance sheet based upon the percentage of construction activities completed at the end of each reporting period. The obligation increased $56 million during the first nine months of 2011. We currently expect Aseng production to commence, and lease payments to begin, by year end 2011.

Ratio of Debt-to-Book Capital   Our ratio of debt-to-book capital was 34% at September 30, 2011 as compared with 25% at December 31, 2010. We define our ratio of debt-to-book capital as total debt (which includes long-term debt excluding unamortized discount, the current portion of long-term debt, and short-term borrowings) divided by the sum of total debt plus shareholders’ equity.

Other Short-Term Borrowings   Our committed credit facility may be 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 amounts outstanding under uncommitted credit lines at September 30, 2011 or December 31, 2010, nor did we borrow any funds under uncommitted credit lines during the first nine months of 2011. Depending upon future credit market conditions, these sources may or may not be available. However, we are not dependent on them to fund our day-to-day operations.

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Dividends We paid total cash dividends of 58 cents per share of our common stock during the first nine months of 2011 and 54 cents per share during the first nine months of 2010. 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 cash proceeds from the exercise of stock options of $32 million during the first nine months of 2011 and $35 million during the first nine months of 2010.

Common Stock Repurchases We receive shares of common stock from employees for the payment of withholding taxes due on the vesting of restricted shares issued under stock-based compensation plans. We received 181,234 shares with a value of $16 million during the first nine months of 2011 and 164,515 shares with a value of $12 million during the first nine months of 2010.

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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, and 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 price changes.

At September 30, 2011, we had entered into variable to fixed price commodity swaps, collars and basis swaps related to crude oil and natural gas sales. Changes in fair value of commodity derivative instruments are reported in earnings in the period in which they occur. Our open commodity derivative instruments were in a net receivable position with a fair value of $125 million. Based on the September 30, 2011 published commodity futures price strips for the underlying commodities, a hypothetical price increase of $1.00 per Bbl for crude oil would decrease the fair value of our net commodity derivative receivable by approximately $17 million. A hypothetical price increase of $0.10 per MMBtu for natural gas would decrease the fair value of our net commodity derivative receivable by approximately $6 million. Our derivative instruments are executed under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net cash settled at the time of election. See Item 1. Financial Statements – Note 6. Derivative Instruments and Hedging Activities.

Interest Rate Risk

Changes in interest rates affect the amount of interest we pay on borrowings under our revolving credit facility and the amount of interest we earn on our short-term investments.

At September 30, 2011, we had approximately $3.5 billion (excluding the FPSO lease obligation and unamortized debt discount) of long-term debt outstanding. Debt outstanding included $3.1 billion of fixed-rate debt with a weighted average interest rate of 6.01%. Although near term changes in interest rates may affect the fair value of our fixed-rate debt, they do not expose us to the risk of earnings or cash flow loss. See Item 1. Financial Statements – Note 5. Debt.

We occasionally enter into interest rate derivative instruments such as forward contracts or swap agreements to hedge exposure to interest rate risk. Changes in fair value of interest rate derivative instruments used as cash flow hedges are reported in AOCL, to the extent the hedge is effective, until the forecasted transaction occurs, at which time they are recorded as adjustments to interest expense. At September 30, 2011, AOCL included $27 million, net of tax, related to interest rate derivative instruments. This amount is currently being reclassified to earnings as adjustments to interest expense over the terms of our 5¼% senior notes due April 2014 and 6% senior notes due March 1, 2041. See Item 1. Financial Statements – Note 6. Derivative Instruments and Hedging Activities.

We are also exposed to interest rate risk related to our interest-bearing cash and cash equivalents balances. As of September 30, 2011, our cash and cash equivalents totaled approximately $1.25 billion, approximately 72% of which was invested in money market funds and short-term investments with major financial institutions. A hypothetical 25 basis point change in the floating interest rates applicable to the amount invested as of September 30, 2011 would result in a change in annual interest income of approximately $2 million.

Foreign Currency Risk

The US dollar is considered the functional currency for each of our international operations. Substantially all of our international crude oil, natural gas and NGL production is sold pursuant to US dollar denominated contracts. Transactions, such as operating costs and administrative expenses that are paid in a foreign currency, are remeasured into US dollars and recorded in the financial statements at prevailing currency exchange rates. Certain monetary assets and liabilities, such as foreign deferred tax liabilities in certain foreign tax jurisdictions, are denominated in a foreign currency. A reduction in the value of the US dollar against currencies of other countries in which we have material operations could result in the use of additional cash to settle operating, administrative, and tax liabilities. This risk may be mitigated to the extent commodity prices increase in response to a devaluation of the US dollar.

Transaction gains or losses were not material in any of the periods presented and are included in other (income) expense, net in the consolidated statements of operations.

We currently have no foreign currency derivative instruments outstanding. However, we may enter into foreign currency derivative instruments (such as forward contracts, costless collars or swap agreements) in the future if we determine that it is necessary to invest in such instruments in order to mitigate our foreign currency exchange risk.

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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;
- the impact of governmental fiscal terms and/or regulation, such as that involving the protection of the environment or marketing of production, as well as other regulations; and
- access to resources.

Forward-looking statements are typically identified by use of terms such as “may,” “will,” “expect,” “believe,” “anticipate,” “estimate,” “intend,” and similar words, although some forward-looking statements may be expressed differently. These forward-looking statements are made based upon our 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, if any, and included in our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2011 and June 30, 2011, and our Annual Report on Form 10-K for the year ended December 31, 2010, which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements. Our Annual Report on Form 10-K for the year ended December 31, 2010 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 our principal executive officer and 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

Piceance Basin Matter   In October 2011, we received a Notice of Alleged Violation (NOAV) from the Colorado Oil and Gas Conservation Commission (Commission) regarding the reporting of gas analyses indicating the presence of hydrogen sulfide to the Commission and local government designee within certain areas of our Piceance basin operations. At this time, the Commission has not established a proposed penalty for this NOAV. Given the inherent uncertainty in administrative actions of this nature, we are unable to predict the ultimate outcome of this action at this time. However, we believe that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on our financial position, results of operations or cash flows.

See Item I. Financial Statements – Note 16. 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 Quarterly Reports on Form 10-Q for the quarters ended March 31, 2011 and June 30, 2011, or our Annual Report on Form 10-K for the year ended December 31, 2010, other than the following:

Our entry into the Marcellus shale through our joint venture with CONSOL will subject us to certain financial, operational and legal obligations and additional risks associated with crude oil and natural gas development activities in that region.

On September 30, 2011 we finalized a joint venture partnership arrangement with CONSOL where, among other things, we have agreed to develop significant acreage in the Marcellus shale. This arrangement represents the entry into a new core area for us in which we have very limited experience. Under the arrangement, we purchased a 50% interest in CONSOL's undeveloped acreage and have agreed to act as operator on a portion of the acreage. Additionally, we have committed to make significant capital expenditures, consisting primarily of a $2.1 billion Carried Cost Obligation, and have agreed to other operational and legal obligations. If we do not meet our financial commitments or perform our other obligations on a timely basis, our rights to participate in the joint venture, and our anticipated operations in the Marcellus shale, could be adversely affected.

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We plan to drill numerous wells in the Marcellus shale over a multi-year period. These activities will be subject to many risks including, among others:

- Development drilling in emerging resource plays such as the Marcellus shale may not result in commercially productive quantities of crude oil and natural gas reserves;
- We have limited exploration and development experience in the Marcellus shale and limited information regarding ultimate recoverable reserves and production decline rates; therefore, our estimates of economically recoverable quantities of crude oil and natural gas reserves may vary substantially and actual production, revenue and expenditures with respect to our reserves likely will vary, possibly materially, from estimates;
- Our operations in the Marcellus shale will require significant additional attention and we may not be able to attract and retain personnel with the necessary skills to successfully carry out our joint development program;
- Our entry into the Marcellus shale will place additional burdens on our financial resources and internal financial controls;
- The high level of current and planned development activity in the Marcellus shale may result in increased competition for drilling rigs and oilfield services such as hydraulic fracturing, gathering, processing and/or transportation, thus hindering our ability to develop our reserves and market our production;
- Significant activism in New York, Pennsylvania and West Virginia against oil and gas development activities, particularly regarding the use of hydraulic fracturing, could, among other things, delay or limit our access to crude oil and natural gas reserves;
- Additional environmental regulation or legislation could result in higher development and/or production costs;
- Enactment of local impact fees in Pennsylvania, such as recommended by the Marcellus Shale Advisory Committee and supported by the governor of Pennsylvania, a severance tax in Pennsylvania, such as has been proposed by various groups in the past, and /or permit fees for drilling such as adopted by a joint legislative committee in West Virginia, would likely result in a lower rate of return on our development project;
- Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our operations, could hinder our ability to develop our reserves or increase our development and operating costs.

We may not be able to compensate for or fully mitigate these risks.

Our ability to produce crude oil and natural gas economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling operations or are unable to dispose of or recycle the water we use at a reasonable cost and in accordance with applicable environmental rules.

The hydraulic fracturing process on which we depend to produce commercial quantities of crude oil and natural gas from many reservoirs, including Wattenberg and the Marcellus shale, require the use and disposal of significant quantities of water.

Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, could adversely impact our operations in these regions. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas.

Compliance with environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial condition.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Period	Total Number of Shares Purchased (1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (in thousands)
07/01/11 - 07/31/11	462	$ 90.73	-	-
08/01/11 - 08/31/11	53	88.39	-	-
09/01/11 - 09/30/11	181	84.56	-	-
Total	696	$ 88.95	-	-

(1)Stock repurchases during the period related to stock received by us from employees for the payment of withholding taxes due on shares issued under stock-based compensation plans.

Item 3. Defaults Upon Senior Securities

None.

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Item 4. (Removed and Reserved)

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, 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 20, 2011

/s/ Kenneth M. Fisher
Kenneth M. Fisher
Senior Vice President, Chief Financial Officer

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Index to Exhibits

Exhibit Number	Exhibit
2.1	Asset Acquisition Agreement dated August 17, 2011 between CNX Gas Company LLC and Noble Energy, Inc. including Annex I (Definitions) thereto, filed herewith.
3.1	Certificate of Incorporation, as amended through May 16, 2005, of the Registrant (filed as Exhibit 3.1 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference).
3.2	By-Laws of Noble Energy, Inc. as amended through June 1, 2009 (filed as Exhibit 3.1 to the Registrant's Current Report on Form 8-K (Date of Event: February 17, 2009) filed February 20, 2009 and incorporated herein by reference).
10.1	Joint Development Agreement dated September 30, 2011 between CNX Gas Company LLC and Noble Energy, Inc., filed herewith.
10.2	$3.0 billion five-year Credit Agreement, dated October 14, 2011, among Noble Energy, Inc., JPMorgan Chase Bank, N.A., as administrative agent, Citibank N.A., as syndication agent, Bank of America, N.A., Mizuho Corporate Bank, LTD., and Morgan Stanley MUFG Loan Partners, LLC, as documentation agents, and certain other commercial lending institutions named therein (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: October 14, 2011) filed October 18, 2011 and incorporated herein by reference).
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), filed herewith.
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), filed herewith.
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), filed herewith.
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), filed herewith.
101.INS	XBRL Instance Document
101.SCH	XBRL Schema Document
101.CAL	XBRL Calculation Linkbase Document
101.LAB	XBRL Label Linkbase Document
101.PRE	XBRL Presentation Linkbase Document
101.DEF	XBRL Definition Linkbase Document