MARATHON OIL CORP
Form 10-Q
November 04, 2011

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

FORM 10-Q

(Mark One)

[X]	QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 For the Quarterly Period Ended September 30, 2011
	OR
[ ]	TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 For the transition period from _____ to _____

Commission file number 1-5153

Marathon Oil Corporation
(Exact name of registrant as specified in its charter)

Delaware	25-0996816
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

5555 San Felipe Road, Houston, TX 77056-2723
(Address of principal executive offices)

(713) 629-6600
(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 ü No

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 ü No

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes No ü

There were 703,721,720 shares of Marathon Oil Corporation common stock outstanding as of October 31, 2011.

MARATHON OIL CORPORATION
Form 10-Q
Quarter Ended September 30, 2011

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Unless the context otherwise indicates, references in this Form 10-Q to “Marathon Oil,” “we,” “our,” or “us” are references to Marathon Oil Corporation, including its wholly-owned and majority-owned subsidiaries, and its ownership interests in equity method investees (corporate entities, partnerships, limited liability companies and other ventures over which Marathon Oil exerts significant influence by virtue of its ownership interest). Any reference to “Marathon” indicates Marathon Oil Corporation as it existed prior to the June 30, 2011 spin-off of the downstream business.

Part I - Financial Information
Item 1. Financial Statements

MARATHON OIL CORPORATION
Consolidated Statements of Income (Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions, except per share data)	2011	2010	2011	2010
Revenues and other income:				
Sales and other operating revenues	$ 3,633	$ 2,839	$ 10,969	$ 8,287
Sales to related parties	16	15	45	41
Income from equity method investments	123	77	360	245
Net gain on disposal of assets	13	-	63	822
Other income	14	24	36	52
Total revenues and other income	3,799	2,955	11,473	9,447
Costs and expenses:				
Cost of revenues (excludes items below)	1,600	1,107	4,671	3,384
Purchases from related parties	57	57	184	132
Depreciation, depletion and amortization	517	530	1,716	1,376
Impairments	-	-	307	439
General and administrative expenses	104	108	371	328
Other taxes	59	44	170	145
Exploration expenses	129	59	504	282
Total costs and expenses	2,466	1,905	7,923	6,086
Income from operations	1,333	1,050	3,550	3,361
Net interest and other	(30)	(16)	(62)	(53)
Loss on early extinguishment of debt	-	-	(279)	(92)
Income from continuing operations before income taxes	1,303	1,034	3,209	3,216
Provision for income taxes	898	567	2,051	1,758
Income from continuing operations	405	467	1,158	1,458
Discontinued operations	-	229	1,239	404
Net income	$ 405	$ 696	$ 2,397	$ 1,862
Per Share Data				
Basic:				
Income from continuing operations	$ 0.57	$ 0.66	$ 1.63	$ 2.06

Discontinued operations	$ -	$ 0.32	$ 1.74	$ 0.57
Net income per share	$ 0.57	$ 0.98	$ 3.37	$ 2.63
Diluted:				
Income from continuing operations	$ 0.57	$ 0.66	$ 1.62	$ 2.05
Discontinued operations	$ -	$ 0.32	$ 1.73	$ 0.57
Net income per share	$ 0.57	$ 0.98	$ 3.35	$ 2.62
Dividends paid	$ 0.15	$ 0.25	$ 0.65	$ 0.74
Weighted average shares:				
Basic	711	710	712	709
Diluted	714	712	716	711

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

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MARATHON OIL CORPORATION
Consolidated Statements of Comprehensive Income (Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2011	2010	2011	2010
Net income	$ 405	$ 696	$ 2,397	$ 1,862
Other comprehensive income				
Post-retirement and post-employment plans				
Change in actuarial gain (loss)	13	(24)	110	134
Spin-off downstream business	-	-	968	-
Income tax benefit (provision) on post-retirement and post-employment plans	6	10	(409)	(73)
Post-retirement and post-employment plans, net of tax	19	(14)	669	61
Derivative hedges				
Net unrecognized gain (loss)	(1)	1	9	5
Spin-off downstream business	-	-	(7)	-
Income tax benefit (provision) on derivatives	-	0	(1)	-
Derivative hedges, net of tax	(1)	1	1	5
Foreign currency translation and other				
Unrealized gain (loss)	-	(1)	(1)	(1)
Income tax provision on foreign currency translation and other	-	1	-	1
Foreign currency translation and other, net of tax	-	-	(1)	-
Other comprehensive income	18	(13)	669	66
Comprehensive income	$ 423	$ 683	$ 3,066	$ 1,928

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

MARATHON OIL CORPORATION
Consolidated Balance Sheets (Unaudited)

(In millions, except per share data)		September 30, 2011		December 31, 2010
Assets				
Current assets:				
Cash and cash equivalents	$	4,633	$	3,951
Receivables, less allowance for doubtful accounts of $2 and $7		1,696		5,972
Receivables from related parties		25		58
Inventories		342		3,453
Other current assets		458		395
Total current assets		7,154		13,829
Equity method investments		1,431		1,802
Property, plant and equipment, less accumulated depreciation, depletion and amortization of $16,731 and $19,805		20,318		32,222
Goodwill		537		1,380
Other noncurrent assets		1,101		781
Total assets	$	30,541	$	50,014
Liabilities				
Current liabilities:				
Accounts payable	$	1,548	$	8,000
Payables to related parties		14		49
Payroll and benefits payable		129		418
Accrued taxes		1,904		1,447
Deferred income taxes		-		324
Other current liabilities		192		580
Long-term debt due within one year		338		295
Total current liabilities		4,125		11,113
Long-term debt		4,705		7,601
Deferred income taxes		2,676		3,569
Defined benefit postretirement plan obligations		667		2,171
Asset retirement obligations		1,337		1,354
Deferred credits and other liabilities		275		435
Total liabilities		13,785		26,243
Commitments and contingencies				
Stockholders' Equity				
Preferred stock – no shares issued and outstanding (no par value, 26 million shares authorized)		-		-
Common stock:				
Issued – 770 million and 770 million shares (par value $1 per share, 1.1 billion shares authorized)		770		770

Securities exchangeable into common stock – no shares issued and outstanding						
(no par value, 29 million shares authorized)		-			-	
Held in treasury, at cost – 66 million and 60 million shares		(2,721	)		(2,665	)
Additional paid-in capital		6,675			6,756	
Retained earnings		12,352			19,907	
Accumulated other comprehensive loss		(328	)		(997	)
Noncontrolling interest		8			-	
Total stockholders' equity		16,756			23,771	
Total liabilities and stockholders' equity	$	30,541		$	50,014	

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

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MARATHON OIL CORPORATION

Consolidated Statements of Cash Flows (Unaudited)

	Nine Months Ended September 30,	
(In millions)	2011	2010
Increase (decrease) in cash and cash equivalents		
Operating activities:		
Net income	$2,397	$1,862
Adjustments to reconcile net income to net cash provided by operating activities:		
Loss on early extinguishment of debt	279	92
Discontinued operations	(1,239)	(404)
Deferred income taxes	(75)	(411)
Depreciation, depletion and amortization	1,716	1,376
Impairments	307	439
Pension and other postretirement benefits, net	28	(39)
Exploratory dry well costs and unproved property impairments	311	122
Net gain on disposal of assets	(63)	(822)
Equity method investments, net	16	34
Changes in:		
Current receivables	202	(124)
Inventories	47	(35)
Current accounts payable and accrued liabilities	361	924
All other operating, net	113	85
Net cash provided by continuing operations	4,400	3,099
Net cash provided by (used in) discontinued operations	1,090	(111)
Net cash provided by operating activities	5,490	2,988
Investing activities:		
Additions to property, plant and equipment	(2,437)	(2,703)
Disposal of assets	385	1,354
Investments - repayments of loans and return of capital	41	35
Investing activities of discontinued operations	(493)	(920)
Property deposit	(120)	-
All other investing, net	13	(22)
Net cash used in investing activities	(2,611)	(2,256)
Financing activities:		
Debt repayments	(2,843)	(620)
Purchases of common stock	(300)	-
Dividends paid	(462)	(526)
Financing activities of discontinued operations	2,916	(8)
Distribution in Spin-off	(1,622)	-
All other financing, net	129	8
Net cash used in financing activities	(2,182)	(1,146)
Effect of exchange rate changes on cash	(15)	-
Net increase (decrease) in cash and cash equivalents	682	(414)
Cash and cash equivalents at beginning of period	3,951	2,057
Cash and cash equivalents at end of period	$4,633	$1,643

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

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MARATHON OIL CORPORATION
Consolidated Statement of Stockholders' Equity (Unaudited)

(In millions)	Preferred Stock	Common Stock	Securities Exchangeable for Common Stock	Treasury Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Non-controlling Interest	Total Stockholders' Equity
December 31, 2010 Balance	$ -	$ 770	$ -	$ (2,665)	$ 6,756	$ 19,907	$ (997)	$ -	$ 23,771
Shares issued - stock based compensation	-	-	-	251	(84)	-	-		167
Shares repurchased	-	-	-	(307)	-	-	-		(307)
Stock-based compensation	-	-	-	-	(2)	-	-		(2)
Net income	-	-	-	-	-	2,397	-		2,397
Other comprehensive income	-	-	-	-	-	-	82		82
Dividends paid	-	-	-	-	-	(462)	-		(462)
Purchase of subsidiary shares from noncontrolling interest	-	-	-	-	-	-	-	8	8
Spin-off of downstream business	-	-	-	-	5	(9,490)	587		(8,898)
September 30, 2011 Balance	$ -	$ 770	$ -	$ (2,721)	$ 6,675	$ 12,352	$ (328)	$ 8	$ 16,756

(Shares in millions)	Preferred Stock	Common Stock	Securities Exchangeable for Common Stock	Treasury Stock
December 31, 2010 Balance	-	770	-	(60)
Shares issued - stock based compensation	-	-	-	6
Shares repurchased	-	-	-	(12)

September 30, 2011 Balance	-	770	-	(66)

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

MARATHON OIL CORPORATION

Notes to Consolidated Financial Statements (Unaudited)

1. Basis of Presentation

These consolidated financial statements are unaudited; however, in the opinion of management, these statements reflect all adjustments necessary for a fair statement of the results for the periods reported. All such adjustments are of a normal recurring nature unless disclosed otherwise. These consolidated financial statements, including notes, have been prepared in accordance with the applicable rules of the Securities and Exchange Commission and do not include all of the information and disclosures required by accounting principles generally accepted in the United States of America for complete financial statements.

As a result of the spin-off (see Note 2), the results of operations for our downstream (Refining, Marketing and Transportation) business have been classified as discontinued operations for all periods presented. The disclosures in this report are presented on the basis of continuing operations, unless otherwise stated. Any reference to "Marathon" indicates Marathon Oil Corporation as it existed prior to the June 30, 2011 spin-off.

These interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Marathon Oil Corporation 2010 Annual Report on Form 10-K. The results of operations for the quarter and nine months ended September 30, 2011 are not necessarily indicative of the results to be expected for the full year.

2. Spin-off Downstream Business

On June 30, 2011, the spin-off of the downstream (Refining, Marketing and Transportation) business was completed, creating two independent energy companies: Marathon Oil Corporation ("Marathon Oil") and Marathon Petroleum Corporation ("MPC"). On June 30, 2011, stockholders of record as of 5:00 p.m. Eastern Daylight Savings time on June 27, 2011 (the "Record Date") received one common share of MPC stock for every two common shares of Marathon stock held as of the Record Date.

In order to affect the spin-off and govern our relationship with MPC after the spin-off, we entered into a Separation and Distribution Agreement, a Tax Sharing Agreement, an Employee Matters Agreement and a Transition Services Agreement. The Separation and Distribution Agreement governed the separation of the downstream business, the distribution of MPC's shares of common stock to our stockholders, transfer of assets and intellectual property, and other matters related to our relationship with MPC. The Separation and Distribution Agreement provides for cross-indemnities between Marathon Oil and MPC. In general, we have agreed to indemnify MPC for any liabilities relating to our historical oil and gas exploration and production operations, oil sands mining operations and integrated gas operations, and MPC has agreed to indemnify us for any liabilities relating to the historical downstream operations.

The Tax Sharing Agreement governs the respective rights, responsibilities and obligations of Marathon Oil and MPC with respect to taxes and tax benefits, the filing of tax returns, the control of audits and other tax matters. In addition, the Tax Sharing Agreement reflects each company's rights and obligations related to taxes that are attributable to periods prior to and including the Separation date and taxes resulting from transactions effected in connection with the

Separation. In general, under the Tax Sharing Agreement, Marathon Oil is responsible for all U.S. federal, state, local and foreign income taxes attributable to Marathon Oil or any of its subsidiaries for any tax period that begins after the date of the spin-off, and MPC is responsible for all taxes attributable to it or its subsidiaries, whether accruing before, on or after the spin-off. The Tax Sharing Agreement contains covenants intended to protect the tax-free status of the spin-off. These covenants may restrict the ability of Marathon Oil and MPC to pursue strategic or other transactions that otherwise could maximize the values of their respective businesses and may discourage or delay a change of control of either company.

The Employee Matters Agreement contains provisions concerning benefit protection for employees who become MPC employees prior to December 31, 2011, treatment of holders of Marathon stock options, stock appreciation rights, restricted stock and restricted stock units, and cooperation between Marathon Oil and MPC in the sharing of employee information and maintenance of confidentiality. Unvested equity-based compensation awards were converted to awards of the entity where the employee holding them is working post-separation. For vested equity-based compensation awards, employees received both Marathon Oil and MPC awards.

Under the Transition Services Agreement, Marathon Oil and MPC are providing and/or making available various administrative services and assets to each other, for up to a one-year period beginning on the distribution date of the spin-off. The services include: administrative services; accounting services; audit services; health, environmental and safety services; human resource services; information technology services; legal services; natural gas administration services; tax services; and treasury services. In consideration for such services, the companies are paying fees to the other for the services provided, and these fees are generally in amounts intended to allow the party providing services to recover all of its direct and indirect costs incurred in providing these services.

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Notes to Consolidated Financial Statements (Unaudited)

The following table presents the carrying value of assets and liabilities of MPC, immediately preceding the spin-off, which is excluded from the Marathon Oil consolidated balance sheet as a result of the spin-off on June 30, 2011.

(In millions)	
Current assets:	
Cash and cash equivalents	$1,622
Receivables	5,041
Inventories	3,679
Other current assets	170
Total current assets of discontinued operations	10,512
Equity method investments	323
Property, plant and equipment	11,935
Goodwill	847
Other noncurrent assets	351
Total assets of discontinued operations	$23,968
Current liabilities:	
Accounts payable	$7,329
Payroll and benefits payable	222
Accrued and deferred taxes	443
Other current liabilities	461
Long-term debt due within one year	12
Total current liabilities of discontinued operations	8,467
Long-term debt	3,262
Deferred income taxes	1,576
Defined benefit postretirement plan obligations	1,489
Deferred credits and other liabilities	276
Total liabilities of discontinued operations	$15,070

The following table presents selected financial information regarding the results of operations of our downstream business which are reported as discontinued operations. Transaction costs incurred to affect the spin-off of $74 million are included in discontinued operations for 2011.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2011	2010	2011	2010
Revenues applicable to discontinued operations	$ -	$ 15,897	$ 38,602	$ 45,054
Pretax income from discontinued operations	-	445	2,012	693

3. Accounting Standards

Not Yet Adopted

In September 2011, the Financial Accounting Standards Board ("FASB") amended accounting standards to simplify how entities test goodwill for impairment. The amendments reduce complexity by allowing an entity the option to make a qualitative evaluation of whether it is necessary to perform the two-step goodwill impairment test. The amendment is effective for our interim and annual periods beginning with the first quarter of 2012. Early adoption is permitted, but we were unable to do so because our 2011 annual goodwill impairment testing was completed prior to the issuance of the amendment. Adoption of this amendment will not have a significant impact on our consolidated results of operations, financial position or cash flows.

The FASB amended the reporting standards for comprehensive income in June 2011 to eliminate the option to present the components of other comprehensive income as part of the statement of changes in stockholders' equity. All non-owner changes in stockholders' equity are required to be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In the two statement approach, the first statement should present total net income and its components followed consecutively by a second statement that should present total other comprehensive income, the components of other comprehensive income, and the total of comprehensive income. The presentation of items that are reclassified from other comprehensive income to net on the income statement is also required. The amendments did not change the items that must be reported in other comprehensive income or when an item of other comprehensive income must be reclassified to net income. The

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Notes to Consolidated Financial Statements (Unaudited)

amendments are effective for us beginning with the first quarter of 2012. We are still evaluating this reporting standard, but we do not expect adoption of this amendment to have an impact on our consolidated results of operations, financial position or cash flows.

In May 2011, the FASB issued an update amending the accounting standards for fair value measurement and disclosure, resulting in common principles and requirements under U.S. generally accepted accounting principles ("U.S. GAAP") and International Financial Reporting Standards ("IFRS"). The amendments change the wording used to describe certain of the U.S. GAAP requirements either to clarify the intent of existing requirements, to change measurement or expand disclosure principles or to conform to the wording used in IFRS. The amendments are to be applied prospectively and will be effective for our interim and annual periods beginning with the first quarter of 2012. Early application is not permitted. We do not expect adoption of these amendments to have a significant impact on our consolidated results of operations, financial position or cash flows.

4. Variable Interest Entities

The Athabasca Oil Sands Project ("AOSP"), in which we hold a 20 percent undivided interest, contracted with a wholly-owned subsidiary of a publicly traded Canadian limited partnership ("Corridor Pipeline") to provide materials transportation capabilities among the Muskeg River and Jackpine mines, the Scotford upgrader and markets in Edmonton. The contract, originally signed in 1999 by a company we acquired, allows each holder of an undivided interest in the AOSP to ship materials in accordance with its undivided interest. Costs under this contract are accrued and recorded on a monthly basis, with a $3 million current liability recorded at September 30, 2011. Under this agreement, the AOSP absorbs all of the operating and capital costs of the pipeline. Currently, no third-party shippers use the pipeline. Should shipments be suspended, by choice or due to force majeure, we remain responsible for the portion of the payments related to our undivided interest for all remaining periods. The contract expires in 2029; however, the shippers can extend its term perpetually. This contract qualifies as a variable interest contractual arrangement and the Corridor Pipeline qualifies as a Variable Interest Entity ("VIE"). We hold a variable interest but are not the primary beneficiary because our shipments are only 20 percent of the total; therefore, the Corridor Pipeline is not consolidated by Marathon Oil. Our maximum exposure to loss as a result of our involvement with this VIE is the amount we expect to pay over the contract term, which was $696 million as of September 30, 2011. The liability on our books related to this contract at any given time will reflect amounts due for the immediately previous month's activity, which is substantially less than the maximum exposure over the contract term. We have not provided financial assistance to Corridor Pipeline and we do not have any guarantees of such assistance in the future.

5. Income per Common Share

Basic income per share is based on the weighted average number of common shares outstanding. Diluted income per share includes exercise of stock options and stock appreciation rights, provided the effect is not antidilutive.

	Three Months Ended September 30,			
	2011		2010	
(In millions, except per share data)	Basic	Diluted	Basic	Diluted

Income from continuing operations	$	405	$	405	$	467	$	467
Discontinued operations		-		-		229		229
Net income	$	405	$	405	$	696	$	696
Weighted average common shares outstanding		711		711		710		710
Effect of dilutive securities		-		3		-		2
Weighted average common shares, including dilutive effect		711		714		710		712
Per share:								
Income from continuing operations	$	0.57	$	0.57	$	0.66	$	0.66
Discontinued operations	$	-	$	-	$	0.32	$	0.32
Net income	$	0.57	$	0.57	$	0.98	$	0.98

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MARATHON OIL CORPORATION

Notes to Consolidated Financial Statements (Unaudited)

	Nine Months Ended September 30,			
	2011		2010	
(In millions, except per share data)	Basic	Diluted	Basic	Diluted
Income from continuing operations	$ 1,158	$ 1,158	$ 1,458	$ 1,458
Discontinued operations	1,239	1,239	404	404
Net income	$ 2,397	$ 2,397	$ 1,862	$ 1,862
Weighted average common shares outstanding	712	712	709	709
Effect of dilutive securities	-	4	-	2
Weighted average common shares, including dilutive effect	712	716	709	711
Per share:				
Income from continuing operations	$ 1.63	$ 1.62	$ 2.06	$ 2.05
Discontinued operations	$ 1.74	$ 1.73	$ 0.57	$ 0.57
Net income	$ 3.37	$ 3.35	$ 2.63	$ 2.62

The per share calculations above exclude 9 million and 7 million stock options and stock appreciation rights for the third quarter and the first nine months of 2011, as they were antidilutive. Excluded in the third quarter and the first nine months of 2010 were 12 million stock options and stock appreciation rights.

6. Acquisitions

During the first nine months of 2011, we acquired approximately 45,000 net acres in the Eagle Ford shale formation in south Texas for approximately $202 million. This was funded from existing cash and was accounted for as an asset acquisition.

Early in the fourth quarter, we closed on the following transactions in Eagle Ford: the previously announced 141,000 net acres from Hilcorp Resources Holdings, LP ("Hilcorp"); additional interests of approximately 19,000 acres net acres; and a gas gathering system. Also, during the fourth quarter, we expect to close on an additional 6,800 net acres in Eagle Ford from tag-along rights. The total acquisition cost for these nearly 167,000 net acres and the gathering system is expected to be approximately $4.5 billion, including projected closing adjustments and future carrying costs. These transactions will be funded largely from existing cash. The acreage includes proved and unproved oil and gas assets, as well as some producing wells. We are in the process of evaluating the acquisitions to determine whether they will be accounted for as business combinations or as asset acquisitions.

7. Dispositions

During the third quarter of 2011, we sold our Integrated Gas segment's equity interest in a liquefied natural gas ("LNG") processing facility in Alaska. A gain on the transaction of $8 million was recorded in the third quarter.

In April 2011, we assigned a 30 percent undivided working interest in our Exploration and Production ("E&P") segment's approximately 180,000 acres in the Niobrara shale play located within the DJ Basin of southeast Wyoming and northern Colorado for total consideration of $270 million, recording a pretax gain of $37 million. We remain operator of this jointly owned leasehold.

Also in April 2011, we farmed-out a 40 percent working interest in 10 concessions in our E&P segment's Poland's Paleozoic Shale play. In late July 2011, we sold an additional 9 percent working interest. A $12 million pretax gain was recorded. We currently hold a 51 percent working interest in these 10 concessions and serve as operator.

In March 2011, we closed the sale of our E&P segment's outside-operated interests in the Gudrun field development and the Brynhild and Eirin exploration areas offshore Norway for net proceeds of $85 million, excluding working capital adjustments. A $64 million pretax loss on this disposition was recorded in the fourth quarter 2010.

During the first quarter 2010, we closed the sale of a 20 percent outside-operated interest in our E&P segment's Production Sharing Contract and Joint Operating Agreement in Block 32 offshore Angola. We received net proceeds of $1.3 billion and recorded a pretax gain on the sale in the amount of $811 million. We retained a 10 percent outside-operated interest in Block 32.

Pending disposition

In October 2011, we entered into definitive agreements to sell our E&P segment's equity interests in several Gulf of Mexico crude oil pipeline systems including our 28 percent interest in Poseidon Oil Pipeline Company, L.L.C., our 29 percent interest in Odyssey Pipeline L.L.C., our 23 percent interest in the Eugene Island Pipeline System, and certain other oil pipeline interests. The value of this transaction, subject to further closing adjustments, is approximately $206

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Notes to Consolidated Financial Statements (Unaudited)

million, net of debt. In addition, the Poseidon and Odyssey interests are subject to wavier of rights of first refusal. The carrying value of these assets was $45 million as of September 30, 2011. We expect to close the transaction in the fourth quarter of 2011.

8. Segment Information

We have three reportable operating segments. Each of these segments is organized and managed based upon the nature of the products and services they offer.

1) Exploration and Production ("E&P") – explores for, produces and markets liquid hydrocarbons and natural gas on a worldwide basis;

2) Oil Sands Mining ("OSM") – mines, extracts and transports bitumen from oil sands deposits in Alberta, Canada, and upgrades the bitumen to produce and market synthetic crude oil and vacuum gas oil; and

3) Integrated Gas ("IG") – markets and transports products manufactured from natural gas, such as liquefied natural gas ("LNG") and methanol, on a worldwide basis.

Segment income represents income from continuing operations, net of income taxes, attributable to the operating segments. Our corporate general and administrative costs are not allocated to the operating segments. These costs primarily consist of employment costs (including pension effects), professional services, facilities and other costs associated with corporate activities, net of associated income tax effects. Foreign currency remeasurement and transaction gains or losses are not allocated to operating segments.

Differences between segment totals for income taxes, depreciation, depletion and amortization and income from equity method investments and our consolidated totals represent amounts related to corporate administrative activities and other unallocated items which are included in "Items not allocated to segments, net of income taxes" in the reconciliation below. Capital expenditures include accruals.

As discussed in Notes 1 and 2, our downstream business was spun-off on June 30, 2011 and has been reported as discontinued operations in all periods presented.

	Three Months Ended September 30, 2011			
(In millions)	E&P	OSM	IG	Total
Revenues:				
Customer	$ 3,190	$ 427	$ 16	$ 3,633
Intersegment	6	-	-	6
Related parties	16	-	-	16

Segment revenues	3,212	427	16	3,655
Elimination of intersegment revenues	(6)	-	-	(6)
Total revenues	$ 3,206	$ 427	$ 16	$ 3,649
Segment income	$ 330	$ 92	$ 55	$ 477
Income from equity method investments	63	-	60	123
Depreciation, depletion and amortization	454	55	-	509
Income tax provision	890	31	19	940
Capital expenditures	684	36	1	721

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	Three Months Ended September 30, 2010			
(In millions)	E&P	OSM	IG	Total
Revenues:				
Customer	$ 2,605	$ 196	$ 38	$ 2,839
Intersegment	20	-	-	20
Related parties	15	-	-	15
Segment revenues	2,640	196	38	2,874
Elimination of intersegment revenues	(20)	-	-	(20)
Total revenues	$ 2,620	$ 196	$ 38	$ 2,854
Segment income	$ 510	$ 18	$ 41	$ 569
Income from equity method investments	51	-	51	102
Depreciation, depletion and amortization	491	28	1	520
Income tax provision	579	2	21	602
Capital expenditures	586	191	1	778

	Nine Months Ended September 30, 2011			
(In millions)	E&P	OSM	IG	Total
Revenues:				
Customer	$ 9,696	$ 1,180	$ 93	$ 10,969
Intersegment	47	-	-	47
Related parties	45	-	-	45
Segment revenues	9,788	1,180	93	11,061
Elimination of intersegment revenues	(47)	-	-	(47)
Total revenues	$ 9,741	$ 1,180	$ 93	$ 11,014
Segment income	$ 1,599	$ 193	$ 158	$ 1,950
Income from equity method investments	187	-	173	360
Depreciation, depletion and amortization	1,541	141	3	1,685
Income tax provision	2,101	64	62	2,227
Capital expenditures	2,101	236	2	2,339

	Nine Months Ended September 30, 2010			
(In millions)	E&P	OSM	IG	Total
Revenues:				
Customer	$ 7,622	$ 567	$ 98	$ 8,287
Intersegment	49	-	-	49
Related parties	41	-	-	41
Segment revenues	7,712	567	98	8,377
Elimination of intersegment revenues	(49)	-	-	(49)
Total revenues	$ 7,663	$ 567	$ 98	$ 8,328
Segment income (loss)	$ 1,444	$ (59)	$ 109	$ 1,494
Income from equity method investments	128	-	142	270
Depreciation, depletion and amortization	1,279	67	3	1,349

Income tax provision (benefit)	1,741	(15)	56	1,782
Capital expenditures	1,774	699	2	2,475

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The following reconciles segment income to net income as reported in the consolidated statements of income:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2011	2010	2011	2010
Segment income	$ 477	$ 569	$ 1,950	$ 1,494
Items not allocated to segments, net of income taxes:				
Corporate and other unallocated items	(79)	(50)	(215)	(130)
Foreign currency remeasurement of income taxes	23	(37)	6	33
Impairments(a)	-	(15)	(195)	(286)
Loss on early extinguishment of debt(b)	-	-	(176)	(57)
Tax effect of subsidiary restructuring(c)	-	-	(122)	-
Deferred income tax items(c)	(15)	-	(65)	(45)
Water abatement - Oil Sands(d)	-	-	(48)	-
Gain on dispositions (e)	(1)	-	23	449
Income from continuing operations	405	467	1,158	1,458
Discontinued operations	-	229	1,239	404
Net income	$ 405	$ 696	$ 2,397	$ 1,862

(a) Impairments are discussed in Note 13.
(b) Additional information on debt retired early can be found in Note 15.
(c) Changes in deferred taxes and the non cash tax restructuring are discussed in Note 10.
(d) Oil sands water abatement costs are discussed in Note 19.
(e) Additional information on these gains can be found in Note 7.

The following reconciles total revenues to sales and other operating revenues as reported in the consolidated statements of income:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2011	2010	2011	2010
Total revenues	$3,649	$2,854	$11,014	$8,328
Less: Sales to related parties	16	15	45	41
Sales and other operating revenues	$3,633	$2,839	$10,969	$8,287

9. Defined Benefit Postretirement Plans

The following summarizes the components of net periodic benefit cost related to continuing operations:

	Three Months Ended September 30,			
	Pension Benefits		Other Benefits	
(In millions)	2011	2010	2011	2010
Service cost	$ 12	$ 12	$ 1	$ -

Interest cost	17	17	4	4
Expected return on plan assets	(16)	(16)	-	-
Amortization:				
– prior service cost (credit)	1	2	(2)	(2)
– actuarial loss	12	12	-	-
– net settlement	-	8	-	-
Net periodic benefit cost	$ 26	$ 35	$ 3	$ 2

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	Nine Months Ended September 30,			
	Pension Benefits		Other Benefits	
(In millions)	2011	2010	2011	2010
Service cost	$ 35	$ 35	$ 3	$ 2
Interest cost	50	52	12	12
Expected return on plan assets	(49)	(48)	-	-
Amortization:				
– prior service cost (credit)	4	5	(5)	(5)
– actuarial loss	37	37	-	-
– net settlement/curtailment loss	-	8	-	-
Net periodic benefit cost	$ 77	$ 89	$ 10	$ 9

During the first nine months of 2011, we made contributions related to continuing operations of $43 million to our funded pension plans. We expect to make additional contributions up to an estimated $13 million to our funded pension plans over the remainder of 2011, most of which were made in October 2011. Current benefit payments related to unfunded pension and other postretirement benefit plans of our continuing operations were $4 million and $14 million during the first nine months of 2011.

10. Income Taxes

The following is an analysis of the effective income tax rates for continuing operations for the periods presented:

	Nine Months Ended September 30,	
	2011	2010
Statutory U.S. income tax rate	35 %	35 %
Effects of foreign operations, including foreign tax credits	7	19
Change in permanent reinvestment assertion	7	-
Adjustments to valuation allowances	11	-
Tax law changes	2	2
Other tax effects	2	(1)
Effective income tax rate for continuing operations	64 %	55 %

Effects of foreign operations

The effective income tax rate is influenced by a variety of factors including the geographic and functional sources of income, the relative magnitude of these sources of income, and foreign currency remeasurement effects. The provision for income taxes is allocated on a discrete, stand-alone basis to pretax segment income and to individual items not allocated to segments. The difference between the total provision and the sum of the amounts allocated to segments and to individual items not allocated to segments is reported in "Corporate and other unallocated items" shown in Note 8.

The effects of foreign operations on our effective tax rate decreased in the first nine months of 2011 as compared to the first nine months of 2010, primarily due to the suspension of all production operations in Libya in the first quarter of 2011, where the statutory tax rate is in excess of 90 percent. This decrease was partially offset by a deferred tax charge of $122 million related to an internal restructuring of our international subsidiaries in the second quarter of

2011.

Change in permanent reinvestment assertion

A principal tax planning strategy available to realize the deferred tax asset for our foreign tax credit benefits relates to the permanent reinvestment of our foreign subsidiaries' earnings, which is reconsidered quarterly to give effect to changes in our portfolio of producing properties and in our tax profile. In the second quarter of 2011, we recorded $716 million of deferred U.S. tax on undistributed earnings of $2,046 million that we previously intended to permanently reinvest in foreign operations. Offsetting this tax expense were associated foreign tax credits of $488 million. In addition, we reduced our valuation allowance related to foreign tax credits by $228 million due to recognizing deferred U.S. tax on previously undistributed earnings.

Adjustments to valuation allowance

The ability to realize the benefit of foreign tax credits is based on certain estimates concerning future operating conditions (particularly as related to prevailing liquid hydrocarbon, natural gas and synthetic crude oil prices), future financial conditions, income generated from foreign sources and Marathon Oil's tax profile in the years that such credits may be claimed. In the third quarter of 2011, we increased the valuation allowance against foreign tax credits by $227

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million because it is more likely than not that we will be unable to realize all U.S. benefits on foreign taxes accrued in 2011. A higher price and production outlook over the next several years for Norway due to better than expected performance contributed to our generating excess foreign tax credits.

During the second quarter of 2011, we recorded a valuation allowance of $18 million on our deferred tax assets related to state operating loss carryforwards. Due to the spin-off (see Note 2), we have determined it is more likely than not that we will be unable to realize all recorded deferred tax assets.

Tax law changes

On July 19, 2011, the U.K. enacted Finance Bill 2011 which increased the rate of the supplementary charge levied on profits from U.K. oil and gas production from 20 percent to 32 percent, effective March 24, 2011. As a result of this legislation, we recorded deferred tax expense of $15 million in the third quarter of 2011.

On May 25, 2011, Michigan enacted legislation that replaced the Michigan Business Tax (“MBT”) with a corporate income tax (“CIT”), effective January 1, 2012. The new CIT legislation eliminates the “book-tax difference deduction” that was provided under the MBT to mitigate the net increase in a taxpayer’s deferred tax liability resulting when Michigan moved from the Single Business Tax, a non-income tax, to the MBT, an income tax, on July 12, 2007. Such a change in the tax law must be recognized in earnings in the period enacted regardless of the effective date. The total effect of tax law changes on deferred tax balances is recorded as income tax expense related to continuing operations in the period the law is enacted, even if a portion of the deferred tax balances relate to discontinued operations. As a result of the new CIT legislation, we recorded an expense of $32 million in the second quarter of 2011.

The Patient Protection and Affordable Care Act (“PPACA”) and the Health Care and Education Reconciliation Act of 2010 (“HCERA”), (together, the “Acts”) were signed in to law in March 2010. The Acts effectively change the tax treatment of federal subsidies paid to sponsors of retiree health benefit plans that provide prescription drug benefits that are at least actuarially equivalent to the corresponding benefits provided under Medicare Part D. The federal subsidy paid to employers was introduced as part of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (the “MPDIMA”). Under the MPDIMA, the federal subsidy does not reduce our income tax deduction for the costs of providing such prescription drug plans nor is it subject to income tax individually. Beginning in 2013, under the Acts, our income tax deduction for the costs of providing Medicare Part D-equivalent prescription drug benefits to retirees will be reduced by the amount of the federal subsidy. Such a change in the tax law must be recognized in earnings in the period enacted regardless of the effective date. The total effect of tax law changes on deferred tax balances is recorded as income tax expense related to continuing operations in the period the law is enacted, even if a portion of the deferred tax balances relate to discontinued operations. As a result, we have recorded a charge of $45 million in the first quarter of 2010 for the write-off of deferred tax assets to reflect the change in the tax treatment of the federal subsidy.

The following table summarizes the activity in unrecognized tax benefits:

	Nine Months Ended September 30,	
(In millions)	2011	2010

Beginning balance	$	103	$	75
Additions based on tax positions related to the current year		3		4
Reductions based on tax positions related to the current year		(3)		(4)
Additions for tax positions of prior years		71		16
Reductions for tax positions of prior years		(24)		(22)
Settlements		(9)		(1)
Ending balance	$	141	$	68

If the unrecognized tax benefits as of September 30, 2011 were recognized, $90 million would affect our effective income tax rate. There were $10 million of uncertain tax positions as of September 30, 2011 for which it is reasonably possible that the amount of unrecognized tax benefits would decrease during the next twelve months.

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11. Inventories

Inventories are carried at the lower of cost or market value. The cost of inventories of crude oil, refined products and merchandise is determined primarily under the last-in, first-out (“LIFO”) method. A significant portion of our inventories were related to our downstream business (see Note 2) at December 31, 2010.

(In millions)	September 30, 2011	December 31, 2010
Liquid hydrocarbons, natural gas and bitumen	$ 135	$ 1,275
Refined products and merchandise	-	1,774
Supplies and sundry items	207	404
Total inventories, at cost	$ 342	$ 3,453

12. Property, Plant and Equipment

(In millions)	September 30, 2011	December 31, 2010
E&P		
United States	$ 14,549	$ 13,532
International	12,270	11,736
Total E&P	26,819	25,268
OSM	9,866	9,631
IG	36	47
RM&T(a)	-	16,624
Corporate	328	457
Total property, plant and equipment	37,049	52,027
Less accumulated depreciation, depletion and amortization	(16,731)	(19,805)
Net property, plant and equipment	$ 20,318	$ 32,222

(a) See Note 2 for a discussion of the spin-off of our downstream (RM&T) business.

In the first quarter 2011, production operations in Libya were suspended and we are not currently making deliveries of hydrocarbons from our interest in the Waha concession in eastern Libya. As of September 30, 2011, our net property, plant and equipment investment in Libya is approximately $758 million and our net proved reserves in Libya were 242 million barrels of oil equivalent (“mmboe”) at December 31, 2010. The return of our operations in Libya to pre-conflict levels is unknown at this time, however, we and our partners in the Waha concession are assessing the condition of our assets and when the resumption of operations will be viable. In addition, payments due to the Libyan government or entities affiliated with the Libyan government have been blocked by the U.S. government under a February 25, 2011 executive order. Such amounts, as of September 30, 2011, primarily related to taxes and royalties due on our January and February 2011 sales totaled approximately $200 million.

Exploratory well costs capitalized greater than one year after completion of drilling were $390 million as of September 30, 2011, an increase of $67 million from December 31, 2010. The resumption of our offshore Norway exploration project in 2011 reduced the total suspended exploratory well costs by $26 million in the first quarter of 2011. Drilling on the Innsbruck prospect, located on Mississippi Canyon Block 993 in the Gulf of Mexico was suspended in the second quarter of 2010 due to the U.S. Department of Interior's drilling moratorium. During the third quarter of 2011, we received an exploration permit and are in the process of obtaining a rig in order to resume drilling on this property. Costs of $88 million related to that project have now been capitalized for greater than one year.

13. Fair Value Measurements

Fair Values - Recurring

As of September 30, 2011, balances related to interest rate swaps accounted for at fair value on a recurring basis were assets of $28 million. The interest rate swaps are in Level 2 of the fair value hierarchy and are measured at fair value with a market approach using market price quotes or a price obtained from third-party services such as Bloomberg L.P. which have been corroborated with data from active markets for similar assets and liabilities. The majority of our 2010 derivatives related to our downstream business. The following table presents assets and liabilities accounted for at fair value on a recurring basis as of December 31, 2010 by fair value hierarchy level.

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	December 31, 2010				
(In millions)	Level 1	Level 2	Level 3	Collateral	Total
Derivative instruments, assets					
Commodity	$ 58	$ -	$ 1	$ 81	$ 140
Interest rate	-	32	-	-	32
Derivative instruments, assets	58	32	1	81	172
Derivative instruments, liabilities					
Commodity	(102)	-	(3)	-	(105)
Derivative instruments, liabilities	$ (102)	$ -	$ (3)	$ -	$ (105)

At December 31, 2010, commodity derivatives in Level 1 are exchange-traded contracts for crude oil, natural gas and refined products measured at fair value with a market approach using the close-of-day settlement price for the market. Commodity derivatives, interest rate derivatives and foreign currency forwards in Level 2 are measured at fair value with a market approach using broker price quotes or prices obtained from third-party services such as Bloomberg L.P. or Platt's, a Division of McGraw-Hill Corporation ("Platt's"), which have been corroborated with data from active markets for similar assets and liabilities. Collateral deposits related to both Level 1 and Level 2 commodity derivatives are in broker accounts covered by master netting agreements. Commodity derivatives in Level 3 are measured at fair value with a market approach using prices obtained from third-party services such as Platt's and price assessments from other independent brokers.

The following is a reconciliation of the net beginning and ending balances recorded for derivative instruments classified as Level 3 in the fair value hierarchy.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2011	2010	2011	2010
Beginning balance	$ -	$ (3)	$ (2)	$ 9
Included in net income	-	4	-	23
Included in other comprehensive income	-	-	-	4
Transfers to Level 2	-	-	-	(30)
Purchases	-	-	-	2
Settlements	-	1	-	(6)
Spin-off downstream business	-	-	2	-
Ending balance	$ -	$ 2	$ -	$ 2

No instruments measured at fair value using Level 3 inputs were held on September 30, 2011. Net income for the third quarter and first nine months of 2010 included unrealized gains of $3 million related to instruments held on September 30, 2010. See Note 14 for the income statement impacts of our derivative instruments.

Fair Values - Nonrecurring

The following tables show the values of assets, by major class, measured at fair value on a nonrecurring basis in periods subsequent to their initial recognition.

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	Three Months Ended September 30,			
	2011		2010	
(In millions)	Fair Value	Impairment	Fair Value	Impairment
Equity method investment	-	-	-	25

	Nine Months Ended September 30,			
	2011		2010	
(In millions)	Fair Value	Impairment	Fair Value	Impairment
Long-lived assets held for use	$ 226	$ 282	$ 146	$ 439
Equity method investment	-	-	-	25
Intangible assets	$ -	$ 25	$ -	$ -

In May 2011, significant water production and reservoir pressure declines occurred at our E&P segment's Droshky development in the Gulf of Mexico. Plans for a waterflood have been cancelled and the field will be produced to abandonment pressures, expected in the first half of 2012. Consequently, 3.4 million barrels of oil equivalent of proved reserves were written off and a $273 million impairment of this long-lived asset to fair value was recorded in the second quarter of 2011. The $226 million fair value of the Droshky development was determined using an income approach based upon internal estimates of future production levels, prices and discount rate, all Level 3 inputs.

In the second quarter of 2011, our outlook for U.S. natural gas prices made it unlikely that sufficient U.S. demand for LNG would materialize by 2021, which is when the rights lapse under arrangements at the Elba Island, Georgia regasification facility. Using an income approach based upon internal estimates of gas prices and future deliveries, which are Level 3 inputs, we determined that the contract had no remaining fair value and recorded a full impairment of this intangible asset held in our Integrated Gas segment.

In March 2010, we completed a reservoir study which resulted in a portion of our Powder River Basin field being removed from plans for future development in our E&P segment. The field's fair value was measured at $144 million, using an income approach based upon internal estimates of future production levels, prices and discount rate which are Level 3 inputs. This resulted in an impairment of $423 million.

Impairments of several other long-lived assets held for use in our E&P segment, that were evaluated in the nine months ended September 30, 2011 and 2010 were a result of reduced drilling expectations, reduction of estimated reserves or declining natural gas prices, and are also reported above. The fair values of those assets were measured using an income approach based upon internal estimates of future production levels, prices and discount rate, which are Level 3 inputs.

Fair Values – Reported

The following table summarizes financial instruments, excluding the derivative financial instruments, and their reported fair value by individual balance sheet line item at September 30, 2011 and December 31, 2010:

	September 30, 2011		December 31, 2010	
(In millions)	Fair Value	Carrying Amount	Fair Value	Carrying Amount
Financial assets				
Other current assets	$ 223	$ 220	$ 226	$ 220
Other noncurrent assets	273	276	396	231
Total financial assets	496	496	622	451
Financial liabilities				
Long-term debt, including current portion(a)	5,636	4,985	8,364	7,527
Deferred credits and other liabilities	33	35	66	67
Total financial liabilities	$ 5,669	$ 5,020	$ 8,430	$ 7,594

(a) Excludes capital leases.

Our current assets and liabilities include financial instruments, the most significant of which are trade accounts receivables and payables. We believe the carrying values of our current assets and liabilities approximate fair value. Our fair value assessment incorporates a variety of considerations, including (1) the short-term duration of the instruments, (2) our investment-grade credit rating, and (3) our historical incurrence of and expected future

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insignificance of bad debt expense, which includes an evaluation of counterparty credit risk. Exceptions to this assessment are:

- receivables from United States Steel Corporation ("United States Steel"), which are reported in other current assets above and discussed below; and
- the current portion of our long-term debt, which is reported with long-term debt above and discussed below.

The current portion of receivables from United States Steel is reported in other current assets, and the long-term portion is included in other noncurrent assets. The fair value of the receivables from United States Steel is measured using an income approach that discounts the future expected payments over the remaining term of the obligations. Because this receivable is not publicly-traded and not easily transferable, a hypothetical market based upon United States Steel's borrowing rate curve is assumed and the majority of inputs to the calculation are Level 3. The industrial revenue bonds are to be redeemed on or before December 31, 2011, the tenth anniversary of the USX Separation.

Fair values of our remaining financial assets included in other noncurrent assets and of our financial liabilities included in deferred credits and other liabilities are measured using an income approach and most inputs are internally generated, which results in a Level 3 classification. Estimated future cash flows are discounted using a rate deemed appropriate to obtain the fair value.

Over 90 percent of our long-term debt instruments are publicly-traded. A market approach based upon quotes from major financial institutions is used to measure the fair value of such debt. Because these quotes cannot be independently verified to an active market they are considered Level 3 inputs. The fair value of our debt that is not publicly-traded is measured using an income approach. The future debt service payments are discounted using the rate at which we currently expect to borrow. All inputs to this calculation are Level 3.

14. Derivatives

For information regarding the fair value measurement of derivative instruments, see Note 13.

The majority of our 2010 derivatives related to our downstream business. The following table presents the gross fair values of derivative instruments, excluding cash collateral, and where they appear on the consolidated balance sheets as of September 30, 2011 and December 31, 2010.

	September 30, 2011			
(In millions)	Asset	Liability	Net Asset	Balance Sheet Location
Fair Value Hedges				
Interest rate	$ 28	$ -	$ 28	Other noncurrent assets

Total Designated Hedges	28	-	28	
Not Designated as Hedges				
Commodity	1	-	1	Other current assets
Total Not Designated as Hedges	1	-	1	
Total	$ 29	$ -	$ 29	

	December 31, 2010			
(In millions)	Asset	Liability	Net Asset	Balance Sheet Location
Fair Value Hedges				
Interest rate	$ 32	$ -	$ 32	Other noncurrent assets
Total Designated Hedges	32	-	32	
Not Designated as Hedges				
Commodity	58	102	(44)	Other current assets
Total Not Designated as Hedges	58	102	(44)	
Total	$ 90	$ 102	$ (12)	

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	December 31, 2010			
(In millions)	Asset	Liability	Net Liability	Balance Sheet Location
Not Designated as Hedges				
Commodity	$ 1	$ 3	$ 2	Other current liabilities
Total Not Designated as Hedges	1	3	2	
Total	$ 1	$ 3	$ 2	

Derivatives Designated as Cash Flow Hedges

As of September 30, 2011, no derivatives were designated as cash flow hedges.

Gains of $10 million related to cash flow hedges were reclassified from accumulated other comprehensive income into net income during the first quarter of 2011. This amortization was accelerated because the related debt was retired.

Derivatives Designated as Fair Value Hedges

In connection with the debt retired in February and March 2011 discussed in Note 15, we settled interest rate swaps with a notional amount of $1,450 million. We recorded a $29 million gain, which reduced the loss on extinguishment of debt.

As of September 30, 2011, we had multiple interest rate swap agreements with a total notional amount of $500 million at a weighted average, LIBOR-based, floating rate of 3.65 percent.

The following table summarizes the pretax effect of derivative instruments designated as hedges of fair value in our consolidated statements of income:

		Gain (Loss)			
		Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	Income Statement Location	2011	2010	2011	2010
Derivative					
Interest rate	Net interest and other financing costs	$ 26	$ 15	$ 25	$ 39
Hedged Item					
Long-term debt	Net interest and other financing costs	$ (26)	$ (15)	$ (25)	$ (39)

Derivatives not Designated as Hedges

The effect related to continuing operations of all derivative instruments not designated as hedges in our consolidated statements of income appear on the sales and other operating revenues line as gains of $2 million and $7 million in the third quarters of 2011 and 2010. For the first nine months of 2011 and 2010 the gains were $3 million and $130 million.

15. Debt

At September 30, 2011, we had no borrowings outstanding, and no borrowings were made during the third quarter and nine months ended September 30, 2011 against our $3 billion revolving credit facility or under our U.S. commercial paper program that is backed by the revolving credit facility.

In February and March 2011, we retired the following debt at a weighted average price equal to 112 percent of face value. A $279 million loss on extinguishment of debt was recognized in the first quarter of 2011. The loss includes related deferred financing and premium costs partially offset by the gain on settled interest rate swaps.

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(In millions)	
6.000% notes due 2012	$400
6.125% notes due 2012	450
8.375% secured notes due 2012(a)	448
6.500% debentures due 2014	700
5.900% notes due 2018	40
7.500% debentures due 2019	460
Total debt purchases	$2,498

(a) These notes were senior secured notes of Marathon Oil Canada Corporation.

In April 2010, we retired $500 million in aggregate principal of our debt under two tender offers at a weighted average price equal to 117 percent of face value. As a result of the tender offers, we recorded a loss on extinguishment of debt of $92 million, including the transaction premium as well as the expensing of related deferred financing costs on the debt in the second quarter of 2010.

In May 2010, United States Steel redeemed $89 million of certain industrial development and environmental improvement bonds.

United States Steel has issued calls for the fourth quarter of 2011 on the remaining environmental revenue bonds for which we remained obligated after the USX Separation.

16. Stock-Based Compensation Plans

Pursuant to the Employee Matters Agreement (see Note 2), we made certain adjustments to the exercise price and number of our stock-based compensation awards, under existing antidilution provisions, with the intention of generally preserving the intrinsic value of the awards immediately prior to the spin-off. Outstanding options to purchase common shares of Marathon stock that were vested prior to the spin-off were adjusted so that the holders of the options hold options to purchase common shares of both Marathon Oil and MPC stock. Unvested stock options and restricted stock were converted to those of the entity where the employee holding them is working post-separation. Adjustments to our stock-based compensation awards did not result in additional compensation expense.

The following table presenting a summary of stock option award and restricted stock award activity for the nine months ended September 30, 2011 reflects the adjustments discussed above.

	Stock Options		Restricted Stock	
	Number of Shares	Weighted Average Exercise Price	Awards	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2010	24,912,261	$24.85	2,084,680	$23.03
Granted	7,676,544 (a)	32.30	2,982,520 (b)	27.85

Options Exercised/Stock Vested	(3,514,758)	15.05	(869,699)	28.28
Cancelled	(403,223)	23.11	(117,543)	23.82
Spin-off downstream business	(6,989,110)	30.94	(289,925)	21.24
Outstanding at September 30, 2011	21,681,714	$24.47	3,790,033	$25.73

(a) The weighted average grant date fair value of stock option awards granted was $10.45 per share.
(b) Beginning in August, 2011, most employees on the U.S., U.K., Canadian and Norwegian payrolls are eligible for a restricted stock grant, based on performance.

17. Stockholders' Equity

As of September 30, 2011, we had acquired 78 million common shares at a cost of $3,222 million under our $5 billion authorized share repurchase program, including 12 million common shares acquired during the third quarter of 2011 at a cost of $300 million.

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18. Supplemental Cash Flow Information

	Nine Months Ended September 30,	
(In millions)	2011	2010
Net cash provided from operating activities:		
Interest paid (net of amounts capitalized)	$ 197	$ 93
Income taxes paid to taxing authorities	2,183	1,426
Noncash investing and financing activities:		
Debt payments made by United States Steel	18	106

The consolidated statements of cash flows exclude changes to the consolidated balance sheets that did not affect cash. The following is a reconciliation of additions to property, plant and equipment to total capital expenditures.

	Nine Months Ended September 30,	
(in millions)	2011	2010
Additions to property, plant and equipment	$ 2,437	$ 2,703
Change in capital accruals	(61)	(201)
Capital expenditures, continuing operations	$ 2,376	$ 2,502

19. Commitments and Contingencies

We are defendant in a number of lawsuits arising in the ordinary course of business, including, but not limited to, royalty claims, contract claims and environmental claims. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe the resolution of these proceedings will not have a material adverse effect on our consolidated financial position, results of operations or cash flows. Certain of these matters are discussed below.

Litigation - In March 2011, Noble Drilling (U.S.) LLC (“Noble”) filed a lawsuit against us in the District Court of Harris County, Texas alleging, among other things, breach of contract, breach of the duty of good faith and fair dealing, and negligent misrepresentation, relating to a multi-year drilling contract for a newly constructed drilling rig to be deployed in the U.S. Gulf of Mexico. We filed an answer in April 2011, contending, among other things, failure to perform, failure to comply with material obligations, failure to mitigate alleged damages and that Noble failed to provide the rig according to the operating, performance and safety requirements specified in the drilling contract. Noble is seeking an unspecified amount of damages. We are vigorously defending this litigation. The ultimate outcome of this lawsuit, including any financial effect on us, remains uncertain. We do not believe an estimate of a reasonably possible loss (or range of loss) can be made for this lawsuit at this time.

Other contingencies - During the second quarter of 2011, the AOSP operator determined the need and developed preliminary plans to address water flow into a previously mined and contained section of the Muskeg River mine. Our share of the estimated costs in the amount of $64 million was recorded to cost of revenues. At September 30, 2011, the remaining liability is $56 million.

Contractual commitments – At September 30, 2011, Marathon’s contract commitments to acquire property, plant and equipment were $2,641 million. The decrease from commitment levels previously reported is primarily due to the spin-off of our downstream business on June 30, 2011. See Note 2 for discussion of the spin-off.

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

Certain sections of Management's Discussion and Analysis of Financial Condition and Results of Operations include forward-looking statements concerning trends or events potentially affecting our business. These statements typically contain words such as "anticipates," "believes," "estimates," "expects," "targets," "plans," "projects," "could," "may," "shou similar words indicating that future outcomes are uncertain. In accordance with "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, which could cause future outcomes to differ materially from those set forth in forward-looking statements. For additional risk factors affecting our business, see Item 1A. Risk Factors in this Form 10-Q and our 2010 Annual Report on Form 10-K.

Spin-off Downstream Business into Independent Company

On June 30, 2011, the spin-off of Marathon's downstream (Refining, Marketing and Transportation) business was completed, creating two independent energy companies: Marathon Petroleum Corporation ("MPC") and Marathon Oil Corporation. Marathon shareholders at the close of business on the record date of June 27, 2011 received one share of MPC common stock for every two shares of Marathon common stock held. Fractional shares of MPC common stock were not distributed and any fractional share of MPC common stock otherwise issuable to a Marathon shareholder was sold in the open market on such shareholder's behalf, and such shareholder received a cash payment with respect to that fractional share. A tax ruling received in June 2011 from the U.S. Internal Revenue Service ("IRS") affirmed the tax-free nature of the spin-off. Activities related to the downstream business have been treated as discontinued operations in all periods presented in this Form 10-Q (see Note 2 to the consolidated financial statements for additional information).

Overview

We are an international energy company with operations in the U.S., Canada, Africa, the Middle East and Europe. Our operations are organized into three reportable segments:

- Exploration and Production ("E&P") which explores for, produces and markets liquid hydrocarbons and natural gas on a worldwide basis.
- Oil Sands Mining ("OSM") which mines, extracts and transports bitumen from oil sands deposits in Alberta, Canada, and upgrades the bitumen to produce and market synthetic crude oil and vacuum gas oil.
- Integrated Gas ("IG") which markets and transports products manufactured from natural gas, such as liquefied natural gas ("LNG") and methanol, on a worldwide basis.

Assets within these three segments are at various stages in their lifecycle and we further classify them as base, growth or exploration. We have a stable group of base assets, which include our OSM and IG segments and traditional E&P assets in Norway, Equatorial Guinea, the U.K. and the U.S. These assets generate much of the cash that will be available for investment in our growth assets and exploration projects. Growth assets are where we expect to make significant investment in order to realize production and reserve increases. We are focused on North America liquid hydrocarbon growth by developing liquids-rich shale play positions, including the establishment of a dominant position in the core of the Eagle Ford shale play. In addition to the North America shale plays, growth assets include the development of Angola Block 31 and our Canadian in-situ assets. Our areas of exploration are Poland, the Iraqi Kurdistan Region and the Gulf of Mexico.

Operating and Financial Highlights

Significant operating and financial highlights during the third quarter of 2011 include:

- Liquid hydrocarbon and natural gas sales of 349 thousand barrels of oil equivalent per day (“mboepd”), of which 60 percent was liquid hydrocarbons

- International liquid hydrocarbon sales, which receive higher prices than West Texas Intermediate (“WTI”) crude oil, were 67 percent of total

- Synthetic crude oil sales of 50 thousand barrels per day (“mbpd”), a 61 percent increase over the same period last year

    - Operating seven rigs and two hydraulic fracturing crews in North Dakota’s Bakken shale play

        - Operating six rigs in the Anadarko Woodford shale play

- Completed the Shi Randall (50 percent working interest) well in the Anadarko Woodford shale which had an initial 30-day production rate of 1,693 mboepd, of which 35 percent was liquids
- Added a second drilling rig in the Niobrara shale play
- Received exploration permits for the Innsbruck (Mississippi Canyon block 993, 85 percent working interest) and Key Largo (Walker Ridge block 578, 60 percent working interest) prospects and lease extensions on 26 blocks in the Gulf of Mexico
- Completed the Ozona well (Garden Banks block 515, 68 percent working interest) as a single zone producer and is ready for first production
- Cash-adjusted debt-to-capital ratio of 2 percent, however, this will increase in the fourth quarter of 2011 upon completion of the Eagle Ford shale and gathering system acquisitions
- Repurchased approximately 12 million common shares at a cost of $300 million

Acquisitions and Dispositions

Early in the fourth quarter, we closed on the following transactions in Eagle Ford: the previously announced 141,000 net acres from Hilcorp Resources Holdings, LP ("Hilcorp"); additional interests of approximately 19,000 acres net acres; and a gas gathering system. Also, during the fourth quarter, we expect to close on an additional 6,800 net acres in Eagle Ford from tag-along rights. The total acquisition cost for these nearly 167,000 net acres and the gathering system is expected to be approximately $4.5 billion, including projected closing adjustments and future carrying costs. These transactions will be funded largely from existing cash. The acreage includes proved and unproved oil and gas assets, as well as some producing wells. We are in the process of evaluating the acquisitions to determine whether they will be accounted for as business combinations or as asset acquisitions.

In October 2011, we entered into definitive agreements to sell our E&P segment's equity interests in several Gulf of Mexico crude oil pipeline systems including our 28 percent interest in Poseidon Oil Pipeline Company, L.L.C., our 29 percent interest in Odyssey Pipeline L.L.C., our 23 percent interest in the Eugene Island Pipeline System, and certain other oil pipeline interests. The value of this transaction, subject to further closing adjustments, is approximately $206 million, net of debt. In addition, the Poseidon and Odyssey interests are subject to wavier of rights of first refusal. The carrying value of these assets was $45 million as of September 30, 2011. We expect to close the transaction in the fourth quarter of 2011.

Completed

During the third quarter of 2011, we sold our Integrated Gas segment's equity interest in a liquefied natural gas ("LNG") processing facility in Alaska. A gain on the transaction of $8 million was recorded in the third quarter.

In April 2011, we assigned a 30 percent undivided working interest in our Exploration and Production ("E&P") segment's approximately 180,000 acres in the Niobrara shale play located within the DJ Basin of southeast Wyoming and northern Colorado for total consideration of $270 million, recording a pretax gain of $37 million. We remain operator of this jointly owned leasehold.

Also in April 2011, we farmed-out a 40 percent working interest in 10 concessions in our E&P segment's Poland's Paleozoic Shale play. In late July 2011, we sold an additional 9 percent working interest. A $12 million pretax gain was recorded. We currently hold a 51 percent working interest in these 10 concessions and serve as operator.

In March 2011, we closed the sale of our E&P segment's outside-operated interests in the Gudrun field development and the Brynhild and Eirin exploration areas offshore Norway for net proceeds of $85 million, excluding working capital adjustments. A $64 million pretax loss on this disposition was recorded in the fourth quarter 2010.

During the first quarter 2010, we closed the sale of a 20 percent outside-operated interest in our E&P segment’s Production Sharing Contract and Joint Operating Agreement in Block 32 offshore Angola. We received net proceeds of $1.3 billion and recorded a pretax gain on the sale in the amount of $811 million. We retained a 10 percent outside-operated interest in Block 32.

Exploration Projects

We have notified our joint venture partner and the Indonesian government that we intend to relinquish the Pasangkayu Production Sharing Contract (PSC). Discussions continue and we are awaiting a government response. We also plan to shift from an operating to a non-operating position in both the Bone Bay and Kumawa PSCs over the coming year.

During the first quarter of 2011, on the Birchwood oil sands lease located in Alberta, Canada, we drilled 94 stratigraphic test wells. The drilling results are currently being evaluated. Initial results are positive, with the wells encountering expected or greater-than-expected reservoir potential.

In April 2011, we announced a discovery on the Atrush block in the Iraqi Kurdistan Region. The Atrush-1 well was drilled to a total depth of approximately 11,000 feet and encountered pay in the Jurassic zones. Test flow rates were more than 6,000 gross barrels per day. We hold a 20 percent non-operated working interest in the Atrush block. A second discovery in the Iraqi Kurdistan Region was the Swara Tika-1 well on the Sarsang block. It was drilled to a total depth of approximately 12,500 feet and encountered 1,500 feet of gross oil column in the Triassic Kura Chine zones. Test flow rates totaled more than 7,000 bpd with associated gas. Test flow rates were limited by tubing sizes and testing equipment. We hold a 25 percent non-operated working interest in the Sarsang block. The Kurdistan Regional Government holds a 4 percent carried interest in both the Atrush and Sarsang blocks.

Libya

Civil unrest, which began in February 2011 in parts of North Africa, escalated to armed conflict in Libya where we have exploration and production operations. During the first quarter 2011, all production operations in Libya were suspended and we are not currently making deliveries of hydrocarbons from our interest in the Waha concession in eastern Libya. The return of our operations in Libya to pre-conflict levels is unknown at this time, however, we and our partners in the Waha concession are assessing the condition of our assets and when the resumption of operations will be viable.

As of September 30, 2011, our net property, plant and equipment investment in Libya is approximately $758 million and our net proved reserves in Libya were 242 million barrels of oil equivalent (“mmboe”) at December 31, 2010. Sales from Libya in 2010 averaged 46,000 barrels of oil equivalent per day and we are in an underlift position of 847 thousand net barrels of liquid hydrocarbons.

In addition, payments due to the Libyan government or entities affiliated with the Libyan government have been blocked by the U.S. government under a February 25, 2011 executive order. As of September 30, 2011, such amounts, primarily related to taxes and royalties due on our January and February 2011 sales, totaled approximately $200 million.

Forward-looking Statements

The above discussions include forward-looking statements with respect to the pending acquisitions in the Eagle Ford shale formation, the status of operations in Libya, the timing and levels of future production (including initial production rates), anticipated future exploratory drilling activity and the intended shift from operating to a non-operating position in Indonesia. Some factors that could potentially affect these forward-looking statements include pricing, supply and demand for petroleum products, the amount of capital available for exploration and development, regulatory constraints, timing of commencing production from new wells, drilling rig availability, unforeseen hazards such as weather conditions, acts of war or terrorists acts and the governmental or military response, and other geological, operating and economic considerations. The completion of the acquisitions in the Eagle Ford shale formation is subject to customary closing conditions. The anticipated shift from operating to a non-operating position in both the Bone Bay and Kumawa PSCs in Indonesia is subject to obtaining necessary government and third-party approvals. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Outlook

Highlights of our expected future activities include:

- Reaching ten operated drilling rigs in the Eagle Ford shale by year end, plus adding add a third crew dedicated to hydraulic fracturing in January and a fourth crew in June 2012. By this time next year we expect to have 17 rigs operating in the Eagle Ford shale.

- Completing the 27 gross operated wells awaiting completion in the Bakken shale in North Dakota, bringing 33 total wells on production before the end of 2011.

  - Acquiring seismic data and drilling seven to nine gross wells in the Niobrara shale DJ Basin by yearend.

- Starting to drill our first well in Poland the fourth quarter of 2011. By the end of 2012, we plan to drill six to seven wells.

- Beginning to drill in the fourth quarter of 2011 on our two operated blocks (Harir and Safen) in the Iraqi Kurdistan Region.

- Executing a seismic program on our Birchwood oil sand lease in Alberta, Canada during the winter of 2011-2012 to continue our evaluation of the reservoir for insitu production.

- Reviewing our global asset portfolio with a goal of divesting between $1.5 and $3 billion of non-core assets over the next two to three years, including a potential farm down of a minority interest in our Gulf of Mexico prospects.

- Progressing toward a 2012 final investment decision on the Quest Carbon Capture and Storage ("”Quest CCS") project which, as announced in the second quarter of 2011, the governments of Alberta and Canada have agreed to partially fund for 865 million Canadian dollars. The financing would be done over a period of 15 years, including development, construction and 10 years of operations. However, the funding is subject to conditions of achieving certain performance objectives.

- Shutdown of the Muskeg River mine in Alberta, Canada for 10 days in October 2011.

- Projecting fourth quarter 2011 E&P segment production of between 360,000 and 370,000 boepd.

The above discussions include forward-looking statements with respect to future exploratory and development drilling activity, number of anticipated drilling rig activity, potential assets sales, the goal of divesting $1.5 to $3 billion on non-core assets and the Quest CCS project. Some factors that could potentially affect these forward-looking statements include pricing, supply and demand for petroleum products, the amount of capital available for exploration and development, regulatory constraints, timing of commencing production from new wells, drilling rig availability, unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response and other geological, operating and economic considerations. Some factors that could potentially affect the sale of $1.5 billion to $3 billion in non-core assets include changes in prices of and demand for crude oil, natural gas and synthetic crude oil, actions of competitors, future financial condition and operating results, and economic, business, competitive and /or regulatory factors affecting our businesses. The Quest CCS project could also be affected by projected costs and availability of materials and labor, and delays in obtaining or conditions imposed by necessary government and third-party approvals. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Market Conditions

Exploration and Production

Prevailing prices for the various qualities of crude oil and natural gas that we produce significantly impact our revenues and cash flows. Prices have been volatile in recent years. The following table lists the benchmark crude oil and natural gas price averages in the third quarter and first nine months of 2011, when compared to the same periods in 2010.

		Three Months Ended September 30,		Nine Months Ended September 30,	
Benchmark		2011	2010	2011	2010
West Texas Intermediate ("WTI") crude oil	(Dollars per barrel)	$ 89.54	$ 76.21	$ 95.47	$ 77.69
Brent (Europe) crude oil	(Dollars per barrel)	$ 113.46	$ 76.86	$ 111.93	$ 77.13
Henry Hub natural gas	(Dollars per mmbtu)(a)	$ 4.19	$ 4.38	$ 4.16	$ 4.59

(a) Settlement date average.

Crude oil prices were higher in 2011 than in 2010 for all periods. Monthly average prices for Dated Brent have been over $100 per barrel since early February 2011. April 2011 WTI averaged $110.04 per barrel, but prices have been declining to an average of $85.61 in the month of September 2011.

Our domestic crude oil production was about 59 percent sour in the third quarter and 62 percent in the first nine months of 2011. Sour crude oil contains more sulfur than light sweet WTI. Sour crude oil also tends to be heavier than and sells at a discount to light sweet crude oil because of its higher refining costs and lower refined product values. Our international crude oil production is relatively sweet and a majority is sold in relation to the Dated Brent crude oil benchmark.

Average natural gas prices have been less volatile in the periods presented. A significant portion of our natural gas production in the lower 48 states of the U.S. is sold at bid-week prices, or first-of-month indices relative to our specific producing areas. Our other major natural gas-producing regions are Europe and Equatorial Guinea, where our natural gas sales have been and, in the case of Equatorial Guinea primarily, still are subject to term contracts, making realized prices in these areas less volatile. The natural gas being sold from these regions, primarily Equatorial Guinea, is at fixed prices; therefore, our reported average natural gas realized prices may not fully track market price movements.

Oil Sands Mining

OSM segment revenues correlate with prevailing market prices for the various qualities of synthetic crude oil and vacuum gas oil we produce. Roughly two-thirds of our normal output mix will track movements in WTI and one-third will track movements in the Canadian heavy sour crude oil market, primarily Western Canadian Select. Output mix can be impacted by operational problems or planned unit outages at the mine or upgrader.

The operating cost structure of the oil sands mining operations is predominantly fixed, and therefore many of the costs incurred in times of full operation continue during production downtime. Per unit costs are sensitive to production rate. Key variable costs are natural gas and diesel fuel, which track commodity markets such as the Canadian Alberta Energy Company (“AECO”) natural gas sales index and crude prices respectively.

The table below shows benchmark prices that impacted both our revenues and variable costs for the third quarter and first nine months of 2011 and 2010:

		Three Months Ended September 30,		Nine Months Ended September 30,	
Benchmark		2011	2010	2011	2010
WTI crude oil	(Dollars per barrel)	$ 89.54	$ 76.21	$ 95.47	$ 77.69
Western Canadian Select	(Dollars per barrel)(a)	$ 72.14	$ 60.55	$ 76.10	$ 64.72
AECO natural gas sales index	(Dollars per mmbtu)(b)	$ 3.70	$ 3.44	$ 3.86	$ 3.99

(a) Monthly pricing based upon average WTI adjusted for differentials unique to western Canada.

(b) Monthly average of Alberta Energy Company ("AECO") day ahead index.

Integrated Gas

Our integrated gas operations include marketing and transportation of products manufactured from natural gas, such as LNG and methanol, primarily in Europe and West Africa.

We have a 60 percent ownership in a production facility in Equatorial Guinea, which sells LNG under a long-term contract at prices tied to Henry Hub natural gas prices. In general, LNG delivered to the U.S. is tied to Henry Hub prices and will track with changes in U.S. natural gas prices, while LNG sold in Europe and Asia is indexed to crude oil prices and will track the movement of those prices.

We own a 45 percent interest in a methanol plant located in Equatorial Guinea through our investment in Atlantic Methanol Production Company LLC ("AMPCO"). Methanol demand has a direct impact on AMPCO's earnings. Because global demand for methanol is rather limited, changes in the supply-demand balance can have a significant impact on sales prices. AMPCO's plant capacity of 1.1 million tonnes is about 3 percent of total world demand.

Results of Operations

Consolidated Results of Operation

Due to the spin-off of our downstream business on June 30, 2011, which is reported as discontinued operations, income from continuing operations is more representative of Marathon Oil as an independent energy company. Consolidated income from continuing operations before income taxes for 2011 was 26 percent higher in the third quarter than in the same period of 2010, largely due to higher liquid hydrocarbon prices. This improvement was offset by a 69 percent continuing operations effective tax rate in the third quarter of 2011 compared to 55 percent in the same period last year. In the third quarter of 2011, Marathon incurred a non-cash charge of $227 million for foreign tax credits which we now expect to be unutilized in current or future periods. A higher production outlook for Norway due to better than expected performance contributed to our generating excess foreign tax credits.

In the first nine months of 2011, consolidated income from continuing operations before income taxes was relatively consistent with the same period of 2010. Higher liquid hydrocarbon prices were offset by lower sales volumes in the E&P segment. For the first nine months of 2011, the continuing operations effective tax rate was 64 percent compared to 55 percent in the same period last year.

Revenues are summarized by segment in the following table:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2011	2010	2011	2010
E&P	$ 3,212	$ 2,640	$ 9,788	$ 7,712
OSM	427	196	1,180	567
IG	16	38	93	98
Segment revenues	3,655	2,874	11,061	8,377
Elimination of intersegment revenues	(6)	(20)	(47)	(49)
Total revenues	$ 3,649	$ 2,854	$ 11,014	$ 8,328

E&P segment revenues increased $572 million in the third quarter and $2,076 million in the first nine months of 2011 from the comparable prior-year periods. Revenues in both 2010 periods include the impact of derivative instruments intended to mitigate price risk on future sales of liquid hydrocarbons and natural gas. Net pretax derivative gains of $13 million and $91 million were reported in the third quarter and first nine months of 2010.

Included in our E&P segment are supply optimization activities which include sales of crude oil and natural gas purchased from partners and nearby producers for sale to satisfy transportation commitments and achieving flexibility in product type and delivery point. Revenues from these supply optimization activities are higher in the third quarter and first nine months of 2011 than in comparable periods in part due higher crude oil prices in 2011.

Revenues from the sale of our production are higher in both periods primarily as a result of higher liquid hydrocarbon price realizations, but sales volumes have been more variable among the periods. The following table gives details of net sales and average realizations of our United States operations.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
United States Operating Statistics				
Net liquid hydrocarbons sales (mbpd)	69	80	73	65
Liquid hydrocarbon average realization (per bbl)	$ 88.89	$ 69.52	$ 91.53	$ 69.95
Net natural gas sales (mmcfd)	296	363	326	350
Natural gas average realization (per mcf)	$ 4.85	$ 4.43	$ 5.04	$ 4.78

The Droshky development in the Gulf of Mexico, which commenced production in July 2010, is the primary reason for the higher liquid hydrocarbon and natural gas sales volumes in the nine-month period of 2011, however, its production rates declined rapidly and is also a reason for lower liquid hydrocarbon and natural gas sales volumes in the third quarter of 2011. In addition to the impact of Droshky on natural gas volumes, sales were lower in the third quarter and first nine months of 2011 as compared to the same periods of 2010 because the Powder River Basin field which was sold in the second quarter of 2010 primarily produced natural gas, and mature fields continue a natural decline, while gas demand in Alaska decreased in the third quarter of 2011.

The following table gives details of net sales and average realizations of our international operations.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
International Operating Statistics				
Net liquid hydrocarbon (mbpd)				
Europe	108	80	102	92
Africa	34	89	44	84
Total International	142	169	146	176
Liquid hydrocarbon average realizations (per bbl)				
Europe	$ 117.05	$ 80.49	$ 115.91	$ 79.69
Africa	63.51	69.24	75.38	69.85
Total International	$ 104.24	$ 74.57	$ 103.75	$ 75.00
Net natural gas sales (mmcfd)				
Europe(a)	79	99	92	104
Africa	453	442	440	399
Total International	532	541	532	503
Natural gas average realizations (per mcf)				
Europe	$ 9.81	$ 7.20	$ 10.07	$ 6.42
Africa	0.24	0.25	0.24	0.25

Total International	$ 1.67	$ 1.52	$ 1.95	$ 1.52

(a) Includes natural gas acquired for injection and subsequent resale of 16 mmcfd and 15 mmcfd for the third quarters of 2011 and 2010, and 15 mmcfd and 19 mmcfd for the first nine months of 2011 and 2010.

Compared to 2010, international liquid hydrocarbon sales volumes for the third quarter and first nine months of 2011 are lower due to the temporary cessation of production from Libya in February 2011. Partially offsetting the impact of Libya in both periods, were higher liquid hydrocarbon sales from Europe primarily due to the timing of liftings and from Equatorial Guinea where a turnaround occurred in the first four months of 2010. Natural gas sales volumes from Equatorial Guinea were likewise higher in the 2011 periods due to this turnaround, while natural gas sales volumes from Europe were down primarily related to planned turnarounds and normal production declines in the U.K.

OSM segment revenues increased $231 million in the third quarter and $613 million in the first nine months of 2011 compared to the same periods of 2010. The impact of derivative instruments intended to mitigate price risk relative to future sales of synthetic crude were losses of $8 million and gains of $34 million the third quarter and first nine months of 2010. All derivative positions closed in December 2010. See Note 14 to the consolidated financial statements for additional information about derivative instruments.

Excluding the derivative effects, segment revenues increased in both periods of 2011 due to higher synthetic crude oil realizations and volumes as shown on the table below.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
OSM Operating Statistics				
Net synthetic crude sales (mbpd)	50	31	43	25
Synthetic crude average realization (per bbl)	$ 87.29	$ 67.83	$ 90.91	$ 69.07

The 2011 sales volumes improved as a result of the Jackpine mine, which commenced operations in late 2010, and the upgrader expansion was completed and commenced operations in the second quarter of 2011. Sales volumes in 2010 were impacted by a turnaround that commenced on March 22, 2010 that caused production to be completely shut down in April, with a staged resumption in May 2010.

IG segment revenues decreased $22 million in the third quarter and $5 million in the first nine months of 2011 compared to the same periods of 2010. Sales of LNG from our Alaska operations declined throughout 2011 as we planned to shut down the LNG facility. In the third quarter of 2011, sales from the LNG facility ceased completely because we sold our equity interest in the facility.

Income from equity method investments increased $46 million in the third quarter of 2011 and $115 million in the first nine months of 2011 from the comparable prior-year periods. Higher commodity prices positively impacted the earnings of our equity method investees.

Net gain on disposal of assets in the third quarter of 2011 primarily relates to sales of assets in Alaska, including the LNG facility sale previously discussed. Net gain on disposal of assets in the first nine months of 2011 also includes a gain of $37 million from assigning a 30 percent undivided working interest in the Niobrara Shale play, where we remain operator. The gain in the first nine months of 2010 primarily related to the $811 million gain on the sale of a 20 percent outside-operated undivided interest in our E&P segment's Production Sharing and Joint Operating Agreement in Block 32 offshore Angola.

Cost of revenues increased $493 million and $1,287 million in the third quarter and first nine months of 2011 from the comparable periods of 2010 primarily due to our supply optimization activities. WTI prices increased 17 percent for the third quarter and 23 percent in the first nine months of 2011.

OSM segment costs increased in total for the third quarter primarily because the Jackpine mine and upgrader expansion operated for the first full quarter. Although gross costs are up due to the increased volumes handled by the expansion, per barrel costs have been declining in comparison with 2010. OSM segment costs also increased in the first nine months of 2011 when compared to the same periods of 2010 due the expansion's operation start-up costs. These increases were partially offset by no turnaround costs in 2011. We incurred $99 million in the first nine months of 2010 associated with the turnaround. Additionally, estimated net costs of $64 million were recorded in the second quarter of 2011 to address water flow in a previously mined and contained area of the Muskeg River mine.

Purchases from related parties increased $52 million in first nine months of 2011 compared to the same periods of 2010. Our most significant related party purchases are from the Alba gas plant in Equatorial Guinea in which we own an equity interest. Higher liquid hydrocarbon prices in 2011 increased the value of those purchases.

Depreciation, depletion and amortization (“DD&A”) decreased $13 million in the third quarter and increased $340 million in the first nine months of 2011 from the comparable prior-year periods. Because both our E&P and OSM segments apply the units-of-production method to the majority of their assets, the previously discussed increases or decreases in sales volumes generally result in similar changes in DD&A. Decreased DD&A in the third quarter reflects the impact of lower E&P segment sales volumes, partially offset by increases in the OSM segment. For the nine-month period, DD&A increased in both the OSM and E&P segments, despite lower sales volumes in the E&P segment. The DD&A rate (expense per barrel of oil equivalent), which is impacted by changes in reserves and capitalized costs, can also cause changes in our DD&A. A higher DD&A rate per barrel related to our domestic E&P operations offset the impact of lower sales volumes. The following table provides DD&A rates for our E&P and OSM segments.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
DD&A rate ($ per boe)				
E&P Segment				
United States	$ 24	$ 21	$ 26	$ 18
International	$ 10	$ 9	$ 10	$ 9
OSM Segment	$ 18	$ 15	$ 17	$ 15

Impairments in the first nine months of 2011 related primarily to our Droshky development in the Gulf of Mexico for $273 million and an intangible asset for a LNG delivery contract at Elba Island. In 2010, impairments were primarily related to the Powder River Basin in the amount of $423 million. See Note 13 to the consolidated financial statements for information about these impairments.

General and administrative expenses increased $43 million in the first nine months of 2011 compared to the same period in 2010 primarily due to additional compensation expense. The first nine months of 2011 also includes higher costs of stock awards due to increased stock price of Marathon before the spin-off.

Other taxes increased $15 million and $25 million in the third quarter and first nine months of 2011 compared to the same periods of 2010. With the increase in revenues, particularly related to higher prices, production and ad valorem taxes also increased.

Exploration expenses were higher in the third quarter and first nine months of 2011 than in the same periods of 2010, primarily due to higher dry well costs. Dry well costs in the third quarter of 2011 included the final costs of the Earb well in Norway which was deemed dry in the second quarter of 2011 and some domestic onshore wells, while dry well costs for the third quarter of 2010 were minimal. Dry wells related to Norway, Indonesia and the Gulf of Mexico for the first nine months of 2011 and to the Gulf of Mexico, Equatorial Guinea and Alaska in the first nine months of 2010. Geologic and seismic costs have increased in 2011 primarily related to the U.S. shale plays and the Iraqi Kurdistan Region. The following table summaries these components of exploration expenses.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2011	2010	2011	2010
Dry well and unproved property impairment	$ 47	$ 11	$ 311	$ 122
Geological, geophysical, seismic	39	12	67	62
Other	43	36	126	98
Total exploration expense	$ 129	$ 59	$ 504	$ 282

Loss on early extinguishment of debt relates to debt retirements in February and March of 2011 and in April of 2010. See Note 15 to the consolidated financial statements for additional discussion of these transactions.

Provision for income taxes increased $331 million and $293 million in the third quarter and first nine months of 2011 from the comparable periods of 2010.

The following is an analysis of the effective income tax rates for the first nine months of 2011 and 2010:

	Nine Months Ended September 30,	
	2011	2010
Statutory U.S. income tax rate	35 %	35 %
Effects of foreign operations, including foreign tax credits	7	19
Change in permanent reinvestment assertion	7	-
Adjustments to valuation allowances	11	-
Tax law changes	2	2

Other tax effects	2		(1	)
Effective income tax rate for continuing operations	64	%	55	%

As discussed in Note 10 to the consolidated financial statements, we suspended production operations in Libya in the first quarter of 2011, where the statutory tax rate is in excess of 90 percent. As a result, the effects of foreign operations on our effective tax rate decreased in the first nine months of 2011 compared to the same period of 2010. This decrease was partially offset by a deferred tax charge of $122 million related to an internal restructuring of our international subsidiaries in the second quarter of 2011.

The ability to realize the benefit of foreign tax credits is based on certain estimates concerning future operating conditions (particularly as related to prevailing liquid hydrocarbon, natural gas and synthetic crude oil prices), future financial conditions, income generated from foreign sources and Marathon Oil's tax profile in the years that such credits may be claimed. During the third quarter of 2011 these estimates were revised. The valuation allowance on our deferred tax assets has increased because it is more likely than not that we will be unable to realize all foreign tax credit benefits recorded on taxes being accrued in 2011.

In the second quarter of 2011, we recorded $716 million of deferred U.S. tax on undistributed earnings of $2,046 million that we previously intended to permanently reinvest in foreign operations. Offsetting this tax expense were associated foreign tax credits of $488 million. In addition, we reduced our valuation allowance related to foreign tax credits by $228 million due to recognizing deferred U.S. tax on previously undistributed earnings.

In the second quarter of 2011, we recorded a valuation allowance of $18 million on our deferred tax assets related to state operating loss carryforwards. Due to the spin-off (see Note 2 to the consolidated financial statements), we have determined it is more likely than not that we will be unable to realize all recorded deferred tax assets.

The effective tax rate is also influenced by a variety of factors including the geographical and functional sources of income, the relative magnitude of these sources of income, foreign currency remeasurement effects, and tax legislation changes. See Note 10 to the consolidated financial statements for further discussion of items impacting our effective tax rate.

The provision for income taxes is allocated on a discrete, stand-alone basis to pretax segment income and to individual items not allocated to segments. The difference between the total provision and the sum of the amounts allocated to segments and to individual items not allocated to segments is reported in corporate and other unallocated items.

Discontinued operations reflect the June 30, 2011 spin-off of our downstream businesses and the historical results of those operations, net of tax, for all periods presented.

Segment Results

Segment income (loss) is summarized in the following table:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2011	2010	2011	2010
E&P				
United States	$ 81	$ 99	$ 237	$ 233
International	249	411	1,362	1,211
E&P segment	330	510	1,599	1,444
OSM	92	18	193	(59)
IG	55	41	158	109
Segment income	477	569	1,950	1,494
Items not allocated to segments, net of income taxes:				
Corporate and other unallocated items	(79)	(50)	(215)	(130)
Foreign currency remeasurement of income taxes	23	(37)	6	33
Impairments	-	(15)	(195)	(286)
Loss on early extinguishment of debt	-	-	(176)	(57)
Tax effect of subsidiary restructuring	-	-	(122)	-
Deferred income tax items	(15)	-	(65)	(45)
Water abatement - Oil Sands	-	-	(48)	-
Gain on dispositions	(1)	-	23	449
Income from continuing operations	405	467	1,158	1,458

Discontinued operations	-	229	1,239	404
Net income	$ 405	$ 696	$ 2,397	$ 1,862

United States E&P income decreased $18 million in the third quarter and increased $4 million in the first nine months of 2011 compared to the same periods of 2010. The income decrease in both the third quarter of 2011 was primarily the result of lower liquid hydrocarbon and natural gas sales volumes, increased production costs and exploration expenses, partially offset by higher liquid hydrocarbon realizations. For the nine-month period, the increase in liquid hydrocarbon realizations and sales volumes were partially offset by increased DD&A, production costs, exploration expenses and lower derivative revenue.

International E&P income decreased $162 million in the third quarter and increased $151 million in the first nine months of 2011 compared to the same periods of 2010. Segment income, before taxes, increased in both periods primarily due to 40 percent and 38 percent higher liquid hydrocarbon price realizations for the third quarter and first nine months of 2011. Decreased sales volumes, as previously discussed, partially offset the benefit of higher realizations, but higher income taxes had the most significant impact on decreasing segment income. As previously discussed, in the third quarter of 2011, a valuation allowance was recorded on our deferred tax assets, as it is more likely than not we will be unable to realize all foreign tax credit benefits recorded on taxes accrued in 2011.

OSM segment income increased $74 million and $252 million in the third quarter and first nine months of 2011. As previously discussed, higher sales volumes and synthetic crude realizations in the third quarter and the first nine months of 2011 were the primary reasons for the increase in income. This was partially offset by increased costs and higher DD&A.

IG segment income increased $14 million and $49 million in the third quarter of 2011 and first nine months of 2011 compared to the same periods of 2010. Third quarter 2011 income also includes the gain on sale of our interest in the Alaska LNG production facility. In Equatorial Guinea, higher third quarter earnings from our equity method investment in Atlantic Methanol Production Company were due to higher methanol sales volumes and realizations. The LNG facility in Equatorial Guinea had operational availability of 97 percent for the third quarter of 2010, but realized prices were below 2010 levels.

Management's Discussion and Analysis of Cash Flows and Liquidity

Cash Flows

Net cash provided by continuing operations totaled $4,400 million in the first nine months of 2011, compared to $3,099 million in the first nine months of 2010 reflecting primarily the impact of higher liquid hydrocarbon prices on operating income.

Net cash used in investing activities totaled $2,611 million in the first nine months of 2011, compared to $2,256 million in the first nine months of 2010. Significant investing activities are additions to property, plant and equipment and disposal of assets. In the first nine months of 2011, most of the additions were in the E&P segment with continued spending on U.S. unconventional resource plays and drilling in Norway, Indonesia and the Iraqi Kurdistan Region. This compares to spending in the first nine months of 2010 which was more focused upon the U.S., particularly the Gulf of Mexico. Spending has slowed compared to 2010 in our OSM segment as the upgrader portion of AOSP Expansion 1 was completed and commenced operations in the second quarter 2011. In the first nine months of 2010, the majority of sales proceeds were from the sale of a portion of our interest in Block 32 offshore Angola. Deposits totaling $120 million were paid in the first nine months of 2011 related to the Eagle Ford shale acreage acquisitions.

For further information regarding capital expenditures by segment, see Supplemental Statistics.

Net cash used in financing activities was $2,182 million in the first nine months of 2011, compared to $1,146 million in the first nine months of 2010. Dividends paid were a significant use of cash in both periods. During the first quarter of 2011, we retired $2.5 billion aggregate principal amount of our debt. In the first nine months of 2010, we retired $500 million aggregate principal value of debt. In connection with the spin-off, we distributed $1.6 billion to MPC in the second quarter of 2011.

Liquidity and Capital Resources

Our main sources of liquidity are cash and cash equivalents, internally generated cash flow from operations, our $3.0 billion committed revolving credit facility and sales of non-core assets. Because of the alternatives available to us, including internally generated cash flow and access to capital markets, we believe that our short-term and long-term liquidity is adequate to fund not only our current operations, but also our near-term and long-term funding requirements including our capital spending programs, dividend payments, defined benefit plan contributions, repayment of debt maturities, share repurchase program, and other amounts that may ultimately be paid in connection with contingencies.

Capital Resources

At September 30, 2011, we had no borrowings against our revolving credit facility and no commercial paper outstanding under our U.S. commercial paper program that is backed by the revolving credit facility.

Our cash-adjusted debt-to-capital ratio (total debt-minus-cash to total debt-plus-equity-minus-cash) was 2 percent at September 30, 2011, compared to 14 percent at December 31, 2010. This cash-adjusted debt-to-capital ratio will increase in the fourth quarter of 2011 upon completion of the Eagle Ford shale acreage and gathering system acquisitions. This includes $217 million of debt that is serviced by United States Steel Corporation ("United States Steel"). United States Steel has issued calls for the fourth quarter of 2011 on the environmental revenue bonds.

(In millions)	September 30, 2011	December 31, 2010
Long-term debt due within one year	$ 338	$ 295
Long-term debt	4,705	7,601
Total debt	$ 5,043	$ 7,896
Cash	$ 4,633	$ 3,951
Equity	$ 16,756	$ 23,771
Calculation:		
Total debt	$ 5,043	$ 7,896
Minus cash	4,633	3,951
Total debt minus cash	$ 410	$ 3,945
Total debt	5,043	7,896
Plus equity	16,756	23,771
Minus cash	4,633	3,951
Total debt plus equity minus cash	$ 17,166	$ 27,716
Cash-adjusted debt-to-capital ratio	2 %	14 %

Capital Requirements

During the fourth quarter of 2011, we are closing the Eagle Ford shale acreage and gathering system acquisitions for approximately $4.5 billion, including projected closing adjustments and future carrying costs. The acquisitions will be funded largely from existing cash balances.

On October 26, 2011, our Board of Directors approved a dividend of 15 cents per share for the third quarter of 2011, payable December 12, 2011 to stockholders of record at the close of business on November 16, 2011.

Since January 2006, our Board of Directors has authorized a common share repurchase program totaling $5 billion. As of September 30, 2011, we had repurchased 78 million common shares at a cost of $3,222 million, with 12 million shares at a cost of $300 million acquired in the third quarter of 2011. Purchases under the program may be in either open market transactions, including block purchases, or in privately negotiated transactions. This program may be changed based upon our financial condition or changes in market conditions and is subject to termination prior to completion. The program's authorization does not include specific price targets or timetables. The timing of purchases under the program will be influenced by cash generated from operations, proceeds from potential asset sales, cash from available borrowings and market conditions.

Our opinions concerning liquidity and our ability to avail ourselves in the future of the financing options mentioned in the above forward-looking statements are based on currently available information. If this information proves to be inaccurate, future availability of financing may be adversely affected. Estimates may differ from actual results. Factors that affect the availability of financing include our performance (as measured by various factors including cash provided from operating activities), the state of worldwide debt and equity markets, investor perceptions and expectations of past and future performance, the global financial climate, and, in particular, with respect to borrowings, the levels of our outstanding debt and credit ratings by rating agencies. The completion of the agreements to purchase assets in the Eagle Ford shale formation is subject to customary closing conditions. The forward-looking statements about our common stock repurchase program are based on current expectations, estimates and projections and are not guarantees of future performance. Actual results may differ materially from these expectations, estimates and projections and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. Some factors that could cause actual results to differ materially are changes in prices of and demand for crude oil, and natural gas, actions of competitors, disruptions or interruptions of our production and mining operations due to unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response thereto, and other operating and economic considerations.

Contractual Cash Obligations

The table below provides aggregated information on our consolidated obligations to make future payments under existing contracts as of September 30, 2011:

(In millions)	Total	2011	2012-2013	2014-2015	Later Years
Long-term debt (excludes interest)(a)	$ 5,035	$ 232	$346	$137	$ 4,320
Sale-leaseback financing					
Capital lease obligations(a)	50	-	23	2	25
Operating lease obligations(a)	261	15	75	57	114
Operating lease obligations under sublease(a)					
Purchase obligations:					
Crude oil and feedstock contracts	76	10	62	3	1
Transportation and related contracts	1,198	97	222	153	726
Contracts to acquire property, plant and equipment	2,641	347	617	568	1,109
LNG terminal operating costs(b)	123	3	26	26	68
Service and materials contracts(c)	890	62	308	122	398
Unconditional purchase obligations(d)	40	8	16	16	-
Commitments for oil and gas exploration (non-capital)(e)	37	27	4	1	5
Other long-term liabilities reported in the consolidated balance sheet(f)	2,800	233	863	717	987
Total contractual cash obligations(g)	$ 13,151	$ 1,034	$2,562	$1,802	$ 7,753

(a) Includes debt and lease obligations assumed by United States Steel upon the USX Separation.

(b) We have the right to deliver 58 bcf of natural gas per year to the Elba Island LNG re-gasification terminal. The agreement's primary term ends in 2021. Pursuant to this agreement, we are also committed to pay for a portion of the operating costs of the terminal.

(c) Service and materials contracts include contracts to purchase services such as utilities, supplies and various other maintenance and operating services.

(d) We are party to a long-term transportation services agreement with Alliance Pipeline. This agreement was used by Alliance Pipeline to secure its financing.

(e) Commitments for oil and gas exploration (non-capital) include estimated costs related to contractually obligated exploratory work programs that are expensed immediately, such as geological and geophysical costs.

(f) Primarily includes obligations for pension and other postretirement benefits including medical and life insurance, which we have estimated through 2019. Also includes amounts for uncertain tax positions.

(g) This table does not include the estimated discounted liability for dismantlement, abandonment and restoration costs of oil and gas properties.

Receivable from United States Steel

We remain obligated (primarily or contingently) for $221 million of certain debt and other financial arrangements for which United States Steel has assumed responsibility for repayment (see the USX Separation in Item 1. of our 2010 Annual Report on Form 10-K). United States Steel has issued calls on the environmental revenue bonds the fourth quarter of 2011. United States Steel reported in its Form 10-Q for the three months ended September 30, 2011 that it believes that its liquidity will be adequate to satisfy its obligations for the foreseeable future.

Environmental Matters

We have incurred and will continue to incur substantial capital, operating and maintenance, and remediation expenditures as a result of environmental laws and regulations. If these expenditures, as with all costs, are not ultimately reflected in the prices of our products and services, our operating results will be adversely affected. We believe that substantially all of our competitors must comply with similar environmental laws and regulations. However, the specific impact on each competitor may vary depending on a number of factors, including the age and location of its operating facilities, marketing areas and production processes.

In August 2011, the Environmental Protection Agency ("U.S. EPA") published proposed New Source Performance Standards ("NSPS") and National Emissions Standards for Hazardous Air Pollutants ("NESHAP") that will both amend existing NSPS and NESHAP standards for oil and gas facilities as well as create a new NSPS for oil and gas production, transmission and distribution facilities. If the proposed rules are finalized without substantial modification, compliance

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with the rules will result in an increase in costs of control, equipment, and labor, and require additional notification, monitoring, reporting, and recordkeeping. The U.S. EPA is required to finalize the rule by April of 2012.

In July 2011, the U.S. EPA finalized a Federal Implementation Plan under the Clean Air Act ("CAA") that includes New Source Review ("NSR") regulations which apply to air emissions sources on Tribal Lands. This rule became effective on August 30, 2011, and requires the registration and/or pre-construction permitting of most of our facilities on Tribal Lands in Wyoming, Oklahoma, and North Dakota. With respect to these facilities, the U.S. EPA has determined that pre-construction permitting is required under the new rules. We do not agree with this assessment and are continuing to work with the U.S. EPA to resolve. However, to minimize pre-construction delays in the near term, we entered into an Administrative Compliance and Consent Agreement ("Agreement") that temporarily suspended the requirement for pre-construction permits for facilities on Tribal Lands in North Dakota as long as permit applications were filed in accordance with the Agreement (discussed further in Legal Proceedings). We cannot reasonably estimate the final financial impact of these new permitting requirements until the U.S. EPA finalizes its internal permitting procedures and expected challenges to the new NSR regulations are resolved.

There have been no other significant changes to our environmental matters subsequent to December 31, 2010.

Other Contingencies

We are defendant in a number of lawsuits arising in the ordinary course of business, including, but not limited to, royalty claims, contract claims and environmental claims. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe the resolution of these proceedings will not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

During the second quarter of 2011, the AOSP operator determined the need and developed preliminary plans to address water flow into a previously mined and contained section of the Muskeg River mine. Our share of the estimated costs in the amount of $64 million was recorded to cost of revenues. At September 30, 2011, the remaining liability is $56 million.

Critical Accounting Estimates

The preparation of financial statements in accordance with generally accepted accounting principles requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Actual results could differ from the estimates and assumptions used.

Certain accounting estimates are considered to be critical if (1) the nature of the estimates and assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change; and (2) the impact of the estimates and assumptions on financial condition or operating performance is material.

There have been no changes to our critical accounting estimates related to continuing operations subsequent to December 31, 2010.

Accounting Standards Not Yet Adopted

In September 2011, the Financial Accounting Standards Board ("FASB") amended accounting standards to simplify how entities test goodwill for impairment. The amendments reduce complexity by allowing an entity the option to make a qualitative evaluation of whether it is necessary to perform the two-step goodwill impairment test. The amendment is effective for our interim and annual periods beginning with the first quarter of 2012. Early adopting is permitted, but we were unable to do so because our annual goodwill impairment testing was completed prior to the issuance of the amendment. Adoption of this amendment will not have a significant impact on our consolidated results of operations, financial position or cash flows.

The FASB amended the reporting standards for comprehensive income in June 2011 to eliminate the option to present the components of other comprehensive income as part of the statement of changes in stockholders' equity. All non-owner changes in stockholders' equity are required to be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In the two statement approach, the first statement should present total net income and its components followed consecutively by a second statement that should present total other comprehensive income, the components of other comprehensive income, and the total of comprehensive income. The presentation of items that are reclassified from other comprehensive income to net on the income statement is also required. The amendments did not change the items that must be reported in other comprehensive income or when an item of other comprehensive income must be reclassified to net income. The amendments are effective for us beginning with the first quarter of 2012. We are still evaluating this reporting standard, but we do not expect adoption of this amendment to have an impact on our consolidated results of operations, financial position or cash flows.

In May 2011, the FASB issued an update amending the accounting standards for fair value measurement and disclosure, resulting in common principles and requirements under U.S. generally accepted accounting principles ("U.S. GAAP") and International Financial Reporting Standards ("IFRS"). The amendments change the wording used to describe certain of the U.S. GAAP requirements either to clarify the intent of existing requirements, to change measurement or expand disclosure principles or to conform to the wording used in IFRS. The amendments are to be applied prospectively and will be effective for our interim and annual periods beginning with the first quarter of 2012. Early application is not permitted. We do not expect adoption of these amendments to have a significant impact on our consolidated results of operations, financial position or cash flows.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

For a detailed discussion of our risk management strategies and our derivative instruments, see Item 7A Quantitative and Qualitative Disclosures about Market Risk, in our 2010 Annual Report on Form 10-K.

Disclosures about how derivatives are reported in our consolidated financial statements and how the fair values of our derivative instruments are measured may be found in Notes 13 and 14 to the consolidated financial statements.

The majority of our previous derivative activity was conducted by our downstream business. Sensitivity of the commodity derivatives and interest rate swaps related to continuing operations has not changed significantly.

Item 4. Controls and Procedures

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) was carried out under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. As of the end of the period covered by this report based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective. During the quarter ended September 30, 2011, there were no changes in our internal control over financial reporting that have materially affected, or were reasonably likely to materially affect, our internal control over financial reporting.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2011	2010	2011	2010
Segment Income (Loss)				
Exploration and Production				
United States	$ 81	$ 99	$ 237	$ 233
International	249	411	1,362	1,211
E&P segment	330	510	1,599	1,444
Oil Sands Mining	92	18	193	(59)
Integrated Gas	55	41	158	109
Segment income	477	569	1,950	1,494
Items not allocated to segments, net of income taxes	(72)	(102)	(792)	(36)
Income from continuing operations	405	467	1,158	1,458
Discontinued operations	-	229	1,239	404
Net income	$ 405	$ 696	$ 2,397	$ 1,862
Capital Expenditures(a)				
Exploration and Production				
United States	$ 502	$ 352	$ 1,407	$ 1,222
International	182	234	694	552
E&P segment	684	586	2,101	1,774
Oil Sands Mining	36	191	236	699
Integrated Gas	1	1	2	2
Corporate	7	13	37	27
Total	$ 728	$ 791	$ 2,376	$ 2,502
Exploration Expenses				
United States	$ 75	$ 34	$ 280	$ 192
International	54	25	224	90
Total	$ 129	$ 59	$ 504	$ 282

(a) Capital expenditures include changes in accruals.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
E&P Operating Statistics				
Net Liquid Hydrocarbon Sales (mbpd)				
United States	69	80	73	65
Europe	108	80	102	92
Africa	34	89	44	84
Total International	142	169	146	176
Worldwide	211	249	219	241
Net Natural Gas Sales (mmcfd)				
United States	296	363	326	350
Europe(b)	79	99	92	104
Africa	453	442	440	399
Total International	532	541	532	503
Worldwide	828	904	858	853
Total Worldwide Sales (mboepd)	349	399	362	382
Average Realizations (e)				
Liquid Hydrocarbons (per bbl)				
United States	$ 88.89	$ 69.52	$ 91.53	$ 69.95
Europe	117.05	80.49	115.91	79.69
Africa	63.51	69.24	75.38	69.85
Total International	104.24	74.57	103.75	75.00
Worldwide	$ 99.24	$ 72.95	$ 99.68	$ 73.64
Natural Gas (per mcf)				
United States	$ 4.85	$ 4.43	$ 5.04	$ 4.78
Europe	9.81	7.20	10.07	6.42
Africa(c)	0.24	0.25	0.24	0.25
Total International	1.67	1.52	1.95	1.52
Worldwide	$ 2.81	$ 2.69	$ 3.12	$ 2.86
OSM Operating Statistics				
Net Synthetic Crude Sales (mbpd) (d)	50	31	43	25
Synthetic Crude Average Realization (per bbl)(e)	$ 87.29	$ 67.83	$ 90.91	$ 69.07
IG Operating Statistics				
Net Sales (mtpd) (f)				
LNG	6,935	7,142	7,121	6,502

Methanol	1,366	1,069	1,310	1,120

(b) Includes natural gas acquired for injection and subsequent resale of 16 mmcfd and 15 mmcfd for the third quarters of 2011 and 2010, and 15 mmcfd and 19 mmcfd for the first nine months of 2011 and 2010.

(c) Primarily represents a fixed price under long-term contracts with Alba Plant LLC, Atlantic Methanol Production Company LLC ("AMPCO") and Equatorial Guinea LNG Holdings Limited ("EGHoldings"), equity method investees. We include our share of Alba Plant LLC's income in our E&P segment and we include our share of AMPCO's and EGHoldings' income in our Integrated Gas segment.

(d) Includes blendstocks.

(e) Excludes gains and losses on derivative instruments.

(f) Includes both consolidated sales volumes and our share of the sales volumes of equity method investees. LNG sales from Alaska are conducted through a consolidated subsidiary. LNG and methanol sales from Equatorial Guinea are conducted through equity method investees.

Part II – OTHER INFORMATION

Item 1. Legal Proceedings

We are defendant in a number of lawsuits arising in the ordinary course of business, including, but not limited to, royalty claims, contract claims and environmental claims. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe the resolution of these proceedings will not have a material adverse effect on our consolidated financial position, results of operations or cash flows. Certain of these matters are discussed below.

In March 2011, Noble Drilling (U.S.) LLC ("Noble") filed a lawsuit against us in the District Court of Harris County, Texas alleging, among other things, breach of contract, breach of the duty of good faith and fair dealing, and negligent misrepresentation, relating to a multi-year drilling contract for a newly constructed drilling rig to be deployed in the U.S. Gulf of Mexico. We filed an answer in April 2011, contending, among other things, failure to perform, failure to comply with material obligations, failure to mitigate alleged damages and that Noble failed to provide the rig according to the operating, performance and safety requirements specified in the drilling contract. Noble is seeking an unspecified amount of damages. We are vigorously defending this litigation. The ultimate outcome of this lawsuit, including any financial effect on us, remains uncertain. We do not believe an estimate of a reasonably probable loss (or range of loss) can be made for this lawsuit at this time.

Environmental Proceedings

As discussed in Item-2: Management's Discussion and Analysis of Financial Condition and Results of Operations – Environmental Matters, in August 2011, we entered into an Administrative Compliance and Consent Agreement with the U.S. EPA that temporarily suspended the requirement for pre-construction permits for our well pad facilities on Tribal Lands in North Dakota as long as permit applications were filed in accordance with the schedule set forth in this Agreement. We also agreed to pay $294,000 in settlement of this matter, which also provided coverage for alleged violations of the Clean Air Act.

We have been working with the North Dakota Department of Health to resolve voluntary disclosures we made in 2009 relating to potential Clean Air Act violations relating to our operations on State lands in the Bakken. The amount of the potential fine is estimated to be $100,000.

SEC Investigation Relating to Libya

On May 25, 2011 we received a subpoena issued by the Securities and Exchange Commission ("SEC") requiring the production of documents related to payments made to the government of Libya, or to officials and persons affiliated with officials of the government of Libya. We have been and intend to continue cooperating with the SEC in its investigation.

Item 1A. Risk Factors

We are subject to various risks and uncertainties in the course of our business. The discussion of such risks and uncertainties may be found under Item 1A. Risk Factors in our 2010 Annual Report on Form 10-K. The following is an update to our risk factors.

The potential adoption of federal and state legislative and regulatory initiatives related to hydraulic fracturing could result in operating restrictions or delays in the completion of oil and gas wells.

Hydraulic fracturing is a commonly used process that involves injecting water, sand, and small volumes of chemicals into the wellbore to fracture the hydrocarbon-bearing rock thousands of feet below the surface to facilitate higher flow of hydrocarbons into the wellbore. The U.S. Congress has considered legislation that would require additional regulation affecting the hydraulic fracturing process. Consideration of new federal regulation and increased state oversight continues to arise. The U.S. EPA announced in the first quarter of 2010 its intention to conduct a comprehensive research study on the potential effects that hydraulic fracturing may have on water quality and public health. The U.S. EPA has begun preparation for the study and expects to complete the study in 2012. In addition, various state-level initiatives in regions with substantial shale gas resources have been or may be proposed or implemented to further regulate hydraulic fracturing practices, limit water withdrawals and water use, require disclosure of fracturing fluid constituents, restrict which additives may be used, or implement temporary or permanent bans on hydraulic fracturing.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas, including from the developing shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal or state laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells and increased compliance costs, which could adversely affect our financial position, results of operations and cash flows.

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

Period	Column (a) Total Number of Shares Purchased (a)		Column (b) Average Price Paid per Share	Column (c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (c)	Column (d) Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (c)
07/01/11 – 07/31/11	7,487		$ 32.68	-	$ 2,080,366,711
08/01/11 – 08/31/11	12,026,149		$ 25.25	11,898,200	$ 1,780,609,536
09/01/11– 09/30/11	43,767	(b)	$ 24.66	-	$ 1,780,609,536
Total	12,077,403		$ 25.25	11,898,200	

(a) 142,319 shares of restricted stock were delivered by employees to Marathon Oil, upon vesting, to satisfy tax withholding requirements.

(b) 36,884 shares were repurchased in open-market transactions to satisfy the requirements for dividend reinvestment under the Marathon Oil Corporation Dividend Reinvestment and Direct Stock Purchase Plan (the "Dividend Reinvestment Plan") by the administrator of the Dividend Reinvestment Plan. Shares needed to meet the requirements of the Dividend Reinvestment Plan are either purchased in the open market or issued directly by Marathon Oil.

(c) We announced a share repurchase program in January 2006, and amended it several times in 2007 for a total authorized program of $5 billion. As of September 30, 2011, 78 million split-adjusted common shares had been acquired at a cost of $3,222 million, which includes transaction fees and commissions that are not reported in the table above.

Item 6. Exhibits

The following exhibits are filed as a part of this report:

		Incorporated by Reference					
Exhibit Number	Exhibit Description	Form	Exhibit	Filing Date	SEC File No.	Filed Herewith	Furnished Herewith
12.1	Computation of Ratio of Earnings to Fixed Charges.					X	
31.1	Certification of Chairman, President and Chief Executive Officer pursuant to Rule 13(a)-14 and 15(d)-14 under the Securities Exchange Act of 1934.					X	
31.2	Certification of Executive Vice President and Chief Financial Officer and Treasurer pursuant to Rule 13(a)-14 and 15(d)-14 under the Securities Exchange Act of 1934.					X	
32.1	Certification of Chairman, President and Chief Executive Officer pursuant to 18 U.S.C. Section 1350.					X	
32.2	Certification of Executive Vice President and Chief Financial Officer and Treasurer pursuant to 18 U.S.C. Section 1350.					X	
101.INS	XBRL Instance Document					X	
101.SCH	XBRL Taxonomy Extension Schema					X	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase					X	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase					X	
101.LAB	XBRL Taxonomy Extension Label Linkbase					X	
101.DEF	XBRL Taxonomy Extension Definitions Linkbase					X	

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.

November 4, 2011	MARATHON OIL CORPORATION
	By: /s/ Michael K. Stewart Michael K. Stewart Vice President, Accounting and Controller