MARATHON OIL CORP
Form 10-Q
November 07, 2012

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, 2012

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 Street, 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 þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No o

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

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

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

There were 706,417,267 shares of Marathon Oil Corporation common stock outstanding as of October 31, 2012.

MARATHON OIL CORPORATION

Form 10-Q

Quarter Ended September 30, 2012

INDEX

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).

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)	2012	2011	2012	2011
Revenues and other income:				
Sales and other operating revenues	$4,018	$3,633	$11,513	$10,969
Sales to related parties	16	16	43	45
Income from equity method investments	122	123	260	360
Net gain (loss) on disposal of assets	(12)	13	126	63
Other income	17	14	43	36
Total revenues and other income	4,161	3,799	11,985	11,473
Costs and expenses:				
Cost of revenues (excludes items below)	1,296	1,600	4,005	4,671
Purchases from related parties	72	57	191	184
Depreciation, depletion and amortization	625	517	1,779	1,716
Impairments	8	—	271	307
General and administrative expenses	139	104	389	371
Other taxes	63	59	208	170
Exploration expenses	176	129	491	504
Total costs and expenses	2,379	2,466	7,334	7,923
Income from operations	1,782	1,333	4,651	3,550
Net interest and other	(53)	(30)	(160)	(62)
Loss on early extinguishment of debt	—	—	—	(279)
Income from continuing operations before income taxes	1,729	1,303	4,491	3,209
Provision for income taxes	1,279	898	3,231	2,051
Income from continuing operations	450	405	1,260	1,158
Discontinued operations	—	—	—	1,239
Net income	$450	$405	$1,260	$2,397
Per Share Data				
Basic:				
Income from continuing operations	$0.64	$0.57	$1.79	$1.63
Discontinued operations	—	—	—	$1.74
Net income	$0.64	$0.57	$1.79	$3.37
Diluted:				
Income from continuing operations	$0.63	$0.57	$1.78	$1.62
Discontinued operations	—	—	—	$1.73
Net income	$0.63	$0.57	$1.78	$3.35
Dividends paid	$0.17	$0.15	$0.51	$0.65
Weighted average shares:				
Basic	706	711	705	712
Diluted	709	714	709	716

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

MARATHON OIL CORPORATION
Consolidated Statements of Comprehensive Income (Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2012	2011	2012	2011
Net income	$450	$405	$1,260	$2,397
Other comprehensive income				
Postretirement and postemployment plans				
Change in actuarial loss and other	(90)	13	(80)	110
Spin-off downstream business	—	—	—	968
Income tax benefit (provision) on postretirement and postemployment plans	32	6	28	(409)
Postretirement and postemployment plans, net of tax	(58)	19	(52)	669
Derivative hedges				
Net unrecognized gain (loss)	1	(1)	1	9
Spin-off downstream business	—	—	—	(7)
Income tax provision on derivatives	—	—	—	(1)
Derivative hedges, net of tax	1	(1)	1	1
Foreign currency translation and other				
Unrealized loss	—	—	—	(1)
Income tax provision on foreign currency translation and other	—	—	—	—
Foreign currency translation and other, net of tax	—	—	—	(1)
Other comprehensive income (loss)	(57)	18	(51)	669
Comprehensive income	$393	$423	$1,209	$3,066

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, 2012	December 31, 2011
Assets		
Current assets:		
Cash and cash equivalents	$671	$493
Receivables	2,553	1,917
Receivables from related parties	22	35
Inventories	324	361
Prepayments	111	96
Deferred tax assets	87	99
Other current assets	269	223
Total current assets	4,037	3,224
Equity method investments	1,319	1,383
Property, plant and equipment, less accumulated depreciation, depletion and amortization of $18,438 and $17,248	27,446	25,324
Goodwill	525	536
Other noncurrent assets	1,231	904
Total assets	$34,558	$31,371
Liabilities		
Current liabilities:		
Commercial paper	$1,839	$—
Accounts payable	2,335	1,864
Payables to related parties	44	18
Payroll and benefits payable	148	193
Accrued taxes	2,027	2,015
Other current liabilities	206	163
Long-term debt due within one year	183	141
Total current liabilities	6,782	4,394
Long-term debt	4,518	4,674
Deferred tax liabilities	2,495	2,544
Defined benefit postretirement plan obligations	817	789
Asset retirement obligations	1,516	1,510
Deferred credits and other liabilities	366	301
Total liabilities	16,494	14,212
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 – 64 million and 66 million shares	(2,607)	(2,716)
Additional paid-in capital	6,634	6,680
Retained earnings	13,688	12,788
Accumulated other comprehensive loss	(421)	(370)

Total equity of Marathon Oil's stockholders	18,064	17,152
Noncontrolling interest	—	7
Total equity	18,064	17,159
Total liabilities and stockholders' equity	$34,558	$31,371

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

4

MARATHON OIL CORPORATION
Consolidated Statements of Cash Flows (Unaudited)

	Nine Months Ended September 30,	
(In millions)	2012	2011
Increase (decrease) in cash and cash equivalents		
Operating activities:		
Net income	$1,260	$2,397
Adjustments to reconcile net income to net cash provided by operating activities:		
Discontinued operations	—	(1,239)
Loss on early extinguishment of debt	—	279
Deferred income taxes	(27)	(75)
Depreciation, depletion and amortization	1,779	1,716
Impairments	271	307
Pension and other postretirement benefits, net	(56)	28
Exploratory dry well costs and unproved property impairments	287	311
Net gain on disposal of assets	(126)	(63)
Equity method investments, net	(14)	16
Changes in:		
Current receivables	(646)	202
Inventories	(6)	47
Current accounts payable and accrued liabilities	156	361
All other operating, net	(66)	113
Net cash provided by continuing operations	2,812	4,400
Net cash provided by discontinued operations	—	1,090
Net cash provided by operating activities	2,812	5,490
Investing activities:		
Acquisitions, net of cash acquired	(806)	—
Additions to property, plant and equipment	(3,509)	(2,437)
Disposal of assets	193	385
Investments - return of capital	42	41
Investing activities of discontinued operations	—	(493)
Property deposit	—	(120)
All other investing, net	49	13
Net cash used in investing activities	(4,031)	(2,611)
Financing activities:		
Commercial paper, net	1,839	—
Debt issuance costs	(9)	—
Debt repayments	(111)	(2,843)
Purchases of common stock	—	(300)
Dividends paid	(360)	(462)
Financing activities of discontinued operations	—	2,916
Distribution in spin-off	—	(1,622)
All other financing, net	26	129
Net cash provided by (used in) financing activities	1,385	(2,182)
Effect of exchange rate changes on cash	12	(15)
Net increase in cash and cash equivalents	178	682
Cash and cash equivalents at beginning of period	493	3,951
Cash and cash equivalents at end of period	$671	$4,633

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 in 2011. 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 2011 Annual Report on Form 10-K. The results of operations for the third quarter and first nine months of 2012 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 business was completed, creating two independent energy companies: 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.

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.

(In millions)	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2011
Revenues applicable to discontinued operations	$—	$38,602
Pretax income from discontinued operations	—	2,012

3. Accounting Standards

Recently Adopted

In September 2011, the Financial Accounting Standards Board (“FASB”) amended accounting standards to simplify how entities test goodwill for impairment. The amendment reduces 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. Adoption of this amendment did 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 (“OCI”) 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 OCI, and total comprehensive income. The presentation of items that are reclassified from OCI to net income on the income statement is also required. The amendments did not change the items that must be reported in OCI or when an item of OCI must be reclassified to net income. The amendments are effective for us beginning with the first quarter of 2012, except for the presentation of reclassifications, which has been deferred. Adoption of these amendments did not have a significant 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 accounting principles generally accepted in the U.S. ("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 for our interim and annual periods beginning with the first quarter of 2012. The adoption of the amendments did not have a significant impact on our consolidated results of operations, financial position or cash flows. To the extent they were necessary, we have made the expanded disclosures in Note 13.

4. Variable Interest Entity

The owners of 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, 2012, consistent with December 31, 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 $697 million as of September 30, 2012. 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,			
	2012		2011	
(In millions, except per share data)	Basic	Diluted	Basic	Diluted
Net income	$450	$450	$405	$405
Weighted average common shares outstanding	706	706	711	711
Effect of dilutive securities	—	3	—	3
Weighted average common shares, including dilutive effect	706	709	711	714
Per share:				
Net income	$0.64	$0.63	$0.57	$0.57

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

	Nine Months Ended September 30,			
	2012		2011	
(In millions, except per share data)	Basic	Diluted	Basic	Diluted
Income from continuing operations	$1,260	$1,260	$1,158	$1,158
Discontinued operations	—	—	1,239	1,239
Net income	$1,260	$1,260	$2,397	$2,397
Weighted average common shares outstanding	705	705	712	712
Effect of dilutive securities	—	4	—	4
Weighted average common shares, including dilutive effect	705	709	712	716
Per share:				
Income from continuing operations	$1.79	$1.78	$1.63	$1.62
Discontinued operations	—	—	$1.74	$1.73
Net income	$1.79	$1.78	$3.37	$3.35

The per share calculations above exclude 10 million stock options and stock appreciation rights for the third quarter and first nine months of 2012, as they were antidilutive. Excluded for the third quarter and first nine months of 2011 were 9 million and 7 million stock options and stock appreciation rights.

6. Acquisitions

We acquired approximately 20,000 net acres in the core of the Eagle Ford shale during the first nine months of 2012. All Eagle Ford properties are included in our Exploration and Production ("E&P") segment. The largest transaction was the acquisition of Paloma Partners II, LLC, which closed August 1, 2012 for cash consideration of $768 million. This transaction was accounted for as a business combination. Smaller transactions closed during the second quarter of 2012.

The following table summarizes the amounts allocated to the assets acquired and liabilities assumed based upon their fair values at the acquisition date:

(In millions)	
Assets:	
Cash	$8
Receivables	22
Inventories	1
Total current assets acquired	31
Property, plant and equipment	822
Total assets acquired	853
Liabilities:	
Accounts payable	78
Asset retirement obligations	7
Total liabilities assumed	85
Net assets acquired	$768

The fair values of assets acquired and liabilities assumed were measured primarily using an income approach, specifically utilizing a discounted cash flow analysis. The estimated fair values were based on significant inputs not observable in the market, and therefore represent Level 3 measurements. Significant inputs included estimated reserve volumes, the expected future production profile, estimated commodity prices and assumptions regarding future operating and development costs. A discount rate of approximately 10 percent was used in the discounted cash flow analysis. The accounting for this transaction is complete. The pro forma impact of this business combination is not material to our consolidated statements of income for the third quarter and first nine months of 2012 and 2011.

8

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

7. Dispositions
2012
In the third quarter of 2012, we sold approximately 5,800 net undeveloped acres located outside the core of the Eagle Ford shale, held by our E&P segment, for proceeds of $9 million. A pretax loss of $18 million was recorded.
In May 2012, we executed agreements to relinquish our E&P segment's operatorship of and participating interests in the Bone Bay and Kumawa exploration licenses in Indonesia. As a result, we accrued and reported a $36 million loss on disposal of assets in the second quarter of 2012. Government ratification of the agreements was received during the third quarter of 2012, which released us from our obligations and further commitments related to these licenses, and we paid the amount accrued.
In April 2012, we entered into agreements to sell all of our E&P segment's assets in Alaska. One transaction closed in the second quarter of 2012 with proceeds and a net pretax gain of $7 million. The remaining transaction, with a value of $375 million before closing adjustments, is currently under review by the U.S. Federal Trade Commission and the Alaska Attorney General's office, which could impact the closing of this transaction. Assets held for sale are included in the September 30, 2012 balance sheet as follows:

(In millions)	
Other current assets	$59
Other noncurrent assets	190
Total assets	249
Other current liabilities	1
Deferred credits and other liabilities	90
Total liabilities	$91

In January 2012, we closed on the sale of our E&P segment's interests in several Gulf of Mexico crude oil pipeline systems for proceeds of $206 million. This includes our equity method interests in Poseidon Oil Pipeline Company, L.L.C. and Odyssey Pipeline L.L.C., as well as certain other oil pipeline interests, including the Eugene Island pipeline system. A pretax gain of $166 million was recorded in the first quarter of 2012.
2011
In September 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 of 2011.
In April 2011, we assigned a 30 percent undivided working interest in our 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 $39 million. We remain operator of this jointly owned leasehold.
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 of 2010.
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.

- Exploration and Production ("E&P") – explores for, produces and markets liquid hydrocarbons and natural gas on a worldwide basis;
- 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
- Integrated Gas ("IG") – produces and markets products manufactured from natural gas, such as LNG and methanol, in Equatorial Guinea.

Information regarding assets by segment is not presented because it is not reviewed by the chief operating decision maker ("CODM"). 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

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

of employment costs (including pension effects), professional services, facilities and other costs associated with corporate activities, net of associated income tax effects. Impairments, gains or losses on disposal of assets or other items that affect comparability (as determined by the CODM) also are not allocated to operating segments. Differences between segment totals and our consolidated totals for income taxes and depreciation, depletion and amortization 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. Total capital expenditures include accruals but not corporate activities.
As discussed in Note 2, our downstream business was spun-off on June 30, 2011 and has been reported as discontinued operations in 2011.

	Three Months Ended September 30, 2012			
(In millions)	E&P	OSM	IG	Total
Revenues:				
Customer	$3,503	$470	$—	$3,973
Related parties	16	—	—	16
Segment revenues	$3,519	$470	$—	3,989
Unrealized gain on crude oil derivative instruments				45
Total revenues				$4,034
Segment income	$486	$65	$39	$590
Income from equity method investments	74	—	48	122
Depreciation, depletion and amortization	556	60	—	616
Income tax provision	1,252	20	9	1,281
Capital expenditures	1,274	41	1	1,316

	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)
Total revenues				$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

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

	Nine Months Ended September 30, 2012			
(In millions)	E&P	OSM	IG	Total
Revenues:				
Customer	$10,284	$1,184	$—	$11,468
Related parties	43	—	—	43
Segment revenues	$10,327	$1,184	$—	11,511
Unrealized gain on crude oil derivative instruments				45
Total revenues				$11,556
Segment income	$1,380	$157	$56	$1,593
Income from equity method investments	176	—	84	260
Depreciation, depletion and amortization	1,593	159	—	1,752
Income tax provision	3,398	51	15	3,464
Capital expenditures	3,459	136	2	3,597

	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)
Total revenues				$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

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)	2012	2011	2012	2011
Total revenues	$4,034	$3,649	$11,556	$11,014
Less: Sales to related parties	16	16	43	45
Sales and other operating revenues	$4,018	$3,633	$11,513	$10,969

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

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)	2012	2011	2012	2011
Segment income	$590	$477	$1,593	$1,950
Items not allocated to segments, net of income taxes:				
Corporate and other unallocated items	(158)	(56)	(267)	(209)
Unrealized gain on crude oil derivative instruments	29	—	29	—
Gain (loss) on dispositions	(11)	(1)	72	23
Impairments	—	—	(167)	(195)
Loss on early extinguishment of debt	—	—	—	(176)
Tax effect of subsidiary restructuring	—	—	—	(122)
Deferred income tax items	—	(15)	—	(65)
Water abatement - Oil Sands	—	—	—	(48)
Income from continuing operations	450	405	1,260	1,158
Discontinued operations	—	—	—	1,239
Net income	$450	$405	$1,260	$2,397

9. Defined Benefit Postretirement Plans

The following summarizes the components of net periodic benefit cost:

	Three Months Ended September 30,			
	Pension Benefits		Other Benefits	
(In millions)	2012	2011	2012	2011
Service cost	$12	$12	$1	$1
Interest cost	16	17	4	4
Expected return on plan assets	(14)	(16)	—	—
Amortization:				
– prior service cost (credit)	2	1	(2)	(2)
– actuarial loss	12	12	—	—
– net settlement loss[(a)]	34	—	—	—
Net periodic benefit cost	$62	$26	$3	$3

	Nine Months Ended September 30,			
	Pension Benefits		Other Benefits	
(In millions)	2012	2011	2012	2011
Service cost	$37	$35	$3	$3
Interest cost	48	50	11	12
Expected return on plan assets	(46)	(49)	—	—
Amortization:				
– prior service cost (credit)	6	4	(5)	(5)
– actuarial loss	37	37	—	—
– net settlement loss[(a)]	34	—	—	—
Net periodic benefit cost	$116	$77	$9	$10

(a) Settlement losses are recorded when lump sum payments from a plan in a period exceed the plan's total service and interest costs for the period. Such settlements occurred in our U.S. pension plans during the third quarter of 2012.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

During the third quarter of 2012, we recorded the effects of partial settlements of our U.S. pension plans. We remeasured the plans' assets and liabilities as of September 30, 2012 and, as a result, recognized settlement expense along with an increase of $103 million in actuarial losses, net of settlement expenses. The net increase in actuarial losses is reported in other comprehensive income.

During the first nine months of 2012, we made contributions of $162 million to our funded pension plans. We expect to make additional contributions up to an estimated $2 million over the remainder of 2012. Current benefit payments related to unfunded pension and other postretirement benefit plans were $7 million and $12 million during the first nine months of 2012.

10. Income Taxes

The effective income tax rate is influenced by a variety of factors including the geographic and functional sources of income and the relative magnitude of these sources of income. 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" in Note 8.

Our effective tax rate in the first nine months of 2012 was 72 percent. This rate is higher than the U.S. statutory rate of 35 percent primarily due to earnings from foreign jurisdictions, primarily Norway and Libya, where the tax rates are in excess of the U.S. statutory rate. An increase in earnings and associated taxes from foreign jurisdictions, primarily Norway, as compared to prior periods caused an increase in our valuation allowance on current year foreign tax credits. In Libya, where the statutory tax rate is in excess of 90 percent, limited production resumed in the fourth quarter of 2011 and liquid hydrocarbon sales resumed in the first quarter of 2012. A reliable estimate of 2012 annual ordinary income from our Libyan operations cannot be made and the range of possible scenarios when including ordinary income from our Libyan operations in the worldwide annual effective tax rate calculation demonstrates significant variability. As such, for the first nine months of 2012, an estimated annual effective tax rate was calculated excluding Libya and applied to consolidated ordinary income excluding Libya and the tax provision applicable to Libyan ordinary income was recorded as a discrete item in the period. Excluding Libya, the effective tax rate would be 64 percent for the first nine months of 2012.

Our effective tax rate in the first nine months of 2011 was 64 percent which is higher than the U.S. statutory tax rate of 35 percent primarily due to earnings from foreign jurisdictions where the tax rates are in excess of the U.S. statutory rate and the valuation allowance recorded against 2011 foreign tax credits. In addition, in the second quarter of 2011, we recorded a deferred tax charge related to an internal restructuring of our international subsidiaries.

The following table summarizes the activity in unrecognized tax benefits:

	Nine Months Ended September 30,	
(In millions)	2012	2011
Beginning balance	$157	$103
Additions based on tax positions related to the current year	2	3
Reductions based on tax positions related to the current year	(1)	(3)
Additions for tax positions of prior years	97	71
Reductions for tax positions of prior years	(66)	(24)
Settlements	(12)	(9)
Ending balance	$177	$141

If the unrecognized tax benefits as of September 30, 2012 were recognized, $114 million would affect our effective income tax rate. There were $143 million of uncertain tax positions as of September 30, 2012 for which it is reasonably possible that the amount of unrecognized tax benefits would decrease during the next twelve months.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

11. Inventories

Inventories are carried at the lower of cost or market value.

(In millions)	September 30, 2012	December 31, 2011
Liquid hydrocarbons, natural gas and bitumen	$72	$147
Supplies and sundry items	252	214
Total inventories, at cost	$324	$361

12. Property, Plant and Equipment

(In millions)	September 30, 2012	December 31, 2011
E&P		
United States	$22,167	$19,679
International	13,185	12,579
Total E&P	35,352	32,258
OSM	10,070	9,936
IG	38	37
Corporate	424	341
Total property, plant and equipment	45,884	42,572
Less accumulated depreciation, depletion and amortization	(18,438)	(17,248)
Net property, plant and equipment	$27,446	$25,324

In the first quarter of 2011, production operations in Libya were suspended. In the fourth quarter of 2011, limited production resumed. Since that time, average net liquid hydrocarbon sales volumes have increased to 49 thousand barrels per day (“mbbld”) in the third quarter of 2012 and 37 mbbld in the first nine months of 2012. We and our partners in the Waha concessions continue to assess the condition of our assets in Libya and uncertainty around sustained production and sales levels remains.

Exploratory well costs capitalized greater than one year after completion of drilling (“suspended”) were $207 million as of September 30, 2012. The net decrease in such costs from December 31, 2011 primarily related to changes in three areas. Norway exploration costs of $55 million incurred between 2009 and 2011 have been suspended for greater than one year, pending commencement of the Boyla development which was submitted to the Norwegian government for approval in June and approved in October 2012. Drilling on the Shenandoah prospect in the Gulf of Mexico resumed in June 2012. Costs of $38 million related to Shenandoah are no longer suspended. The Innsbruck well was reentered in September 2012; therefore, costs of $60 million related to the prospect are no longer suspended.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

13. Fair Value Measurements
Fair Values - Recurring
The following table presents assets and liabilities accounted for at fair value on a recurring basis as of September 30, 2012 by fair value hierarchy level.

	September 30, 2012				
(In millions)	Level 1	Level 2	Level 3	Collateral	Total
Derivative instruments, assets					
Commodity	$—	$47	$—	$1	$48
Interest rate	—	22	—	—	22
Foreign currency	—	20	—	—	20
Derivative instruments, assets	—	89	—	1	90
Derivative instruments, liabilities					
Commodity	—	2	—	—	2
Foreign currency	—	1	—	—	1
Derivative instruments, liabilities	$—	$3	$—	$—	$3

Commodity swaps in Level 2 are measured at fair value with a market approach using prices obtained from exchanges or pricing services, which have been corroborated with data from active markets for similar assets and liabilities. Commodity options in Level 2 are valued using The Black-Scholes Model. Inputs to this model include prices as noted above, discount factors, and implied market volatility. The inputs used to estimate fair value are categorized as Level 2 because predominantly all assumptions and inputs are observable in active markets throughout the term of the instruments. Collateral deposits related to commodity derivatives are in broker accounts covered by master netting agreements.
Interest rate swaps are measured at fair value with a market approach using actionable broker quotes which are Level 2 inputs. Foreign currency forwards are measured at fair value with a market approach using third-party pricing services, such as Bloomberg L.P., which have been corroborated with data from active markets for similar assets and liabilities, and are Level 2 inputs.
As of December 31, 2011, balances related to interest rate swaps accounted for at fair value on a recurring basis were noncurrent assets of $5 million measured at fair value using actionable broker quotes which are Level 2 inputs. There were no other significant recurring fair value measurements as of December 31, 2011.
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.

	Three Months Ended September 30,			
	2012		2011	
(In millions)	Fair Value	Impairment	Fair Value	Impairment
Long-lived assets held for use	$2	$8	$—	$—

	Nine Months Ended September 30,			
	2012		2011	
(In millions)	Fair Value	Impairment	Fair Value	Impairment
Long-lived assets held for use	$77	$271	$226	$282
Intangible assets	$—	$—	$—	$25

Our E&P segment's Ozona development in the Gulf of Mexico began production in December 2011. During the first quarter of 2012, production rates declined significantly and have remained below initial expectations. Accordingly, our reserve engineers performed an evaluation of our future production as well as our reserves which concluded in early April 2012. This resulted in a

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

2 million barrel of oil equivalent reduction in proved reserves and a $261 million impairment charge in the first quarter of 2012. The fair value of the Ozona development was determined using an income approach based upon internal estimates of future production levels, prices and discount rate, all Level 3 inputs. Inputs to the fair value measurement included reserve and production estimates made by our reservoir engineers, estimated liquid hydrocarbon prices based on the Louisiana Light Sweet 12-month price range, as we think production will not be significant beyond twelve months, adjusted for quality and location differentials, and forecasted operating expenses for the remaining estimated life of the reservoir.

In May 2011, significant water production and reservoir pressure declines occurred at our E&P segment's Droshky development in the Gulf of Mexico. 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 indicated that it was unlikely that sufficient U.S. demand for LNG would materialize by 2021, which is when our rights lapse under arrangements at the Elba Island, Georgia regasification facility. Using an income approach based upon internal estimates of natural 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.

Other impairments of long-lived assets held for use by our E&P segment in the third quarter and first nine months of 2012 and 2011 were a result of reduced drilling expectations, reduction of estimated reserves or declining natural gas prices. The fair values of those assets were measured using an income approach based upon internal estimates of future production levels, commodity prices and discount rate, which are Level 3 inputs.

Fair Values – Reported

Our current assets and liabilities include financial instruments, the most significant of which are accounts receivables and payables. We believe the carrying values of these accounts receivables and payables 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 insignificance of bad debt expense, which includes an evaluation of counterparty credit risk.

The following table summarizes financial instruments, excluding trade accounts receivables and payables and derivative financial instruments, and their reported fair value by individual balance sheet line item at September 30, 2012 and December 31, 2011:

	September 30, 2012		December 31, 2011	
(In millions)	Fair Value	Carrying Amount	Fair Value	Carrying Amount
Financial assets				
Other current assets	$135	$134	$146	$148
Other noncurrent assets	158	158	68	68
Total financial assets	293	292	214	216
Financial liabilities				
Other current liabilities	13	13	—	—
Long-term debt, including current portion[a]	5,639	4,653	5,479	4,753
Deferred credits and other liabilities	100	101	36	38
Total financial liabilities	$5,752	$4,767	$5,515	$4,791

(a) Excludes capital leases.

Fair values of our remaining financial assets included in other current assets and other noncurrent assets and of our financial liabilities included in other current liabilities and 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.

Most 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

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

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 following table presents the gross fair values of derivatives instruments, excluding cash collateral, and where they appear on the consolidated balance sheets as of September 30, 2012.

	September 30, 2012			
(In millions)	Asset	Liability	Net Asset	Balance Sheet Location
Fair Value Hedges				
Foreign currency	$20	$—	$20	Other current assets
Interest rate	22	—	22	Other noncurrent assets
Total Designated Hedges	42	—	42	
Not Designated as Hedges				
Commodity	30	—	30	Other current assets
Commodity	20	—	20	Other noncurrent assets
Total Not Designated as Hedges	50	—	50	
Total	$92	$—	$92	

	September 30, 2012			
(In millions)	Asset	Liability	Net Liability	Balance Sheet Location
Fair Value Hedges				
Foreign currency	$—	$1	$1	Other current liabilities
Total Designated Hedges	—	1	1	
Not Designated as Hedges				
Commodity	—	5	5	Other current liabilities
Total Not Designated as Hedges	—	5	5	
Total	$—	$6	$6	

As of December 31, 2011, our derivatives outstanding were interest rate swaps that were fair value hedges, which had an asset value of $5 million and are located on the consolidated balance sheet in Other noncurrent assets.

Derivatives Designated as Fair Value Hedges

As of September 30, 2012, we had multiple interest rate swap agreements with a total notional amount of $600 million at a weighted average, London Interbank Offer Rate (“LIBOR”)-based, floating rate of 4.71 percent.

As of September 30, 2012, our foreign currency forwards had an aggregate notional amount of 3,939 million Norwegian Kroner at a weighted average forward rate of 5.911. These forwards hedge our current Norwegian tax liability and have settlement dates through February 2013.

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.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

The pretax effect of derivative instruments designated as hedges of fair value in our consolidated statements of income are summarized in the table below.

		Gain (Loss) Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	Income Statement Location	2012	2011	2012	2011
Derivative					
Interest rate	Net interest and other	$6	$26	$17	$25
Interest rate	Loss on early extinguishment of debt	—	—	—	29
Foreign currency	Provision for income taxes	$22	$—	$(18)	$—
Hedged Item					
Long-term debt	Net interest and other	$(6)	$(26)	$(17)	$(25)
Long-term debt	Loss on early extinguishment of debt	—	—	—	(29)
Accrued taxes	Provision for income taxes	$(22)	$—	$18	$—

Derivatives not Designated as Hedges

In August 2012, we entered crude oil derivatives related to a portion of our forecast U.S. E&P crude oil sales through December 31, 2013. These commodity derivatives were not designated as hedges and are shown in the table below.

Term	Bbls per Day	Weighted Average Price per Bbl	Benchmark
Swaps			
October 2012 - December 2013	20,000	$96.29	West Texas Intermediate
October 2012 - December 2013	25,000	$109.19	Brent
Option Collars			
October 2012 - December 2013	15,000	$90.00 floor / $101.17 ceiling	West Texas Intermediate
October 2012 - December 2013	15,000	$100.00 floor / $116.30 ceiling	Brent

The following table summarizes the effect of all derivative instruments not designated as hedges in our consolidated statements of income.

		Gain (Loss) Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	Income Statement Location	2012	2011	2012	2011
Commodity	Sales and other operating revenues	$45	$2	$46	$3

15. Debt

On October 29, 2012, we issued $1 billion aggregate principal amount of senior notes bearing interest at 0.9 percent with a maturity date of November 1, 2015 and $1 billion aggregate principal amount of senior notes bearing interest at 2.8 percent with a maturity date of November 1, 2022. Interest on the senior notes is payable semi-annually beginning May 1, 2013. The proceeds are being used to pay off commercial paper and for general corporate purposes.

At September 30, 2012, we had no borrowings against our revolving credit facility, described below, and $1,839 million in commercial paper outstanding under our U.S. commercial paper program that is backed by the revolving credit facility.

In April 2012, we terminated our $3.0 billion five-year revolving credit facility and replaced it with a new $2.5 billion unsecured five-year revolving credit facility (the "Credit Facility"). The Credit Facility matures in April 2017 but allows us to request two one-year extensions. It contains an option to increase the commitment amount by up to an additional $1.0 billion, subject to the consent of any increasing lenders, and includes sub-facilities for swing-line loans and letters of credit up to an aggregate amount of $100 million and $500 million, respectively. Fees on the unused commitment of each lender range from 10 basis points to 25 basis points depending on our credit ratings. Borrowings under the Credit Facility bear interest, at our option,

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

at either (a) an adjusted LIBOR rate plus a margin ranging from 87.5 basis points to 162.5 basis points per year depending on our credit ratings or (b) the Base Rate plus a margin ranging from 0.0 basis points to 62.5 basis points depending on our credit ratings. Base Rate is defined as a per annum rate equal to the greatest of (a) the prime rate, (b) the federal funds rate plus one-half of one percent and (c) LIBOR for a one-month interest period plus 1 percent. The agreement contains a covenant that requires our ratio of total debt to total capitalization not to exceed 65 percent as of the last day of each fiscal quarter. If an event of default occurs, the lenders may terminate the commitments under the Credit Facility and require the immediate repayment of all outstanding borrowings and the cash collateralization of all outstanding letters of credit under the Credit Facility.

In the second quarter of 2012, we retired the remaining $23 million principal amount of our 5.375 percent revenue bonds due December 2013. No gain or loss was recorded on this early extinguishment of debt. During the first quarter of 2012, $53 million principal amount of debt carrying a 9.375 percent interest rate was repaid at maturity. During the first quarter of 2011, we retired $2,498 million aggregate principal amount of debt at a weighted average price equal to 112 percent of face value. A $279 million loss on early 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.

16. Incentive Based Compensation

Stock Option and Restricted Stock Awards

The following table presents a summary of stock option award and restricted stock award activity for the first nine months of 2012:

	Stock Options		Restricted Stock	
	Number of Shares	Weighted Average Exercise Price	Awards	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2011	21,370,715	$24.41	3,703,978	$25.88
Granted	1,858,872 [a]	$33.52	2,169,744	$31.61
Options Exercised/Stock Vested	(1,256,318)	$18.25	(1,142,195)	$25.18
Cancelled	(509,748)	$28.29	(287,278)	$27.96
Outstanding at September 30, 2012	21,463,521	$25.47	4,444,249	$28.72

[a] The weighted average grant date fair value of stock option awards granted was $9.94 per share.

Performance Unit Awards

During the first quarter of 2012, we granted 13 million performance units to executive officers. These units have a 36-month performance period.

17. Supplemental Cash Flow Information

	Nine Months Ended September 30,	
(In millions)	2012	2011
Net cash provided from operating activities:		
Interest paid (net of amounts capitalized)	$164	$197
Income taxes paid to taxing authorities	3,457	2,183
Commercial paper, net:		
Commercial paper - issuances	$10,420	$—
- repayments	(8,581)	—
Noncash investing activities:		
Debt payments made by United States Steel	$19	$18
Liabilities assumed in acquisition	85	—
Change in capital expenditure accrual	170	(61)

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

18. 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 for 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.

Guarantees – After our 2009 sale of the subsidiary holding our interest in the Corrib natural gas development offshore Ireland, one guarantee of that entity's performance related to asset retirement obligations remains issued to certain Irish government entities until the Irish government and the current Corrib partners agree to release our guarantee and accept the purchaser's guarantee to replace it. The maximum potential undiscounted payments related to asset retirement obligations under this guarantee as of September 30, 2012 are $40 million.

Contractual commitments – At September 30, 2012 and December 31, 2011, Marathon’s contract commitments to acquire property, plant and equipment were $974 million and $664 million.

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

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 produces and markets products manufactured from natural gas, such as liquefied natural gas ("LNG") and methanol, in Equatorial Guinea.

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," "should 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 the forward-looking statements. For additional risk factors affecting our business, see Item 1A. Risk Factors in our 2011 Annual Report on Form 10-K.

Key Operating and Financial Activities

In the third quarter of 2012, notable items were:

- Net liquid hydrocarbon and natural gas sales volumes of 452 thousand barrels of oil equivalent per day ("mboed"), of which 65 percent was liquid hydrocarbons
- Net international liquid hydrocarbon sales volumes, for which average realizations have exceeded West Texas Intermediate ("WTI") crude oil, were 62 percent of total liquid hydrocarbon sales
- Eagle Ford shale average net sales volumes of 40 mboed, an increase of 90 percent from the second quarter of 2012
- Production from Libya increased over the second quarter of 2012, with average net sales of 53 mboed
- Bakken shale average net sales volumes of 30 mboed, a 87 percent increase over the same quarter of last year
- Closed the acquisition of Paloma Partners II, LLC
- Assumed operatorship of the Vilje field offshore Norway

Some significant fourth quarter activities through November 7, 2012 include:

- Closed acquisition of an additional 4,300 net acres in the core of the Eagle Ford shale
- Signed agreement for a 20 percent non-operated interest in the South Omo concession onshore Ethiopia
- Reentered Gabon by acquiring an interest in an exploration license
- Acquired interests in two onshore exploration blocks in Kenya
- Farmed out 35 percent working interests in the Harir and Safen blocks in the Kurdistan Region of Iraq
- Issued $2 billion of senior notes

Overview and Outlook
Exploration and Production
Production

Net liquid hydrocarbon and natural gas sales averaged 452 mboed during the third quarter and 414 mboed in the first nine months of 2012 compared to 349 mboed and 362 mboed in the same periods of 2011. Net liquid hydrocarbon sales volumes increased in the U.S. for both the third quarter and first nine months of 2012, reflecting the impact of production from the Eagle Ford shale assets acquired in the fourth quarter of 2011 and our ongoing development programs in the Eagle Ford, Bakken and Anadarko Woodford shale resource plays. The resumption of sales from Libya in the first quarter of 2012 after production had ceased there in February of 2011 was the most significant increase in international sales volumes. In addition, net liquid hydrocarbon sales volumes from the U.K. were lower in the 2012 periods than in the same periods of 2011 due to turnarounds in the third quarter and the timing of liftings.

In 2012, we continued to ramp up operations in the core of the Eagle Ford shale play in Texas. Average net sales volumes from the Eagle Ford shale were 40 mboed and 25 mboed in the third quarter and first nine months of 2012. As announced in August, we have reduced our rig count to 18 operated rigs while maintaining four dedicated hydraulic fracturing crews and two more on a spot basis. During the third quarter of 2012, we drilled 78 gross wells and brought 73 gross wells to sales for a total of 180 gross wells drilled in the first nine months of 2012. Our average time to drill a well in the Eagle Ford shale has decreased to approximately 24 days; therefore, we now expect to drill 250 to 260 gross Eagle Ford wells during 2012, an increase of approximately 20 wells from previous estimates. In addition to the improvements in the speed and efficiency in drilling and completions, we continue to optimize well spacing which could significantly increase drillable locations and recoverable resources. We have been performing spacing pilot programs in the Eagle Ford shale which will complete early in 2013 so that we will have applicable technical results by mid-year. To complement drilling and completion activity in the Eagle Ford shale, we continue to build infrastructure to support production growth across the operating area. We are now able to transport approximately 60 percent of our Eagle Ford production by pipeline.

Average net sales volumes from the Bakken shale were 30 mboed and 27 mboed in the third quarter and first nine months of 2012 compared to 17 mboed and 15 mboed in the same periods of 2011. Our Bakken shale liquid hydrocarbon volumes averaged approximately 90 percent crude oil, 5 percent natural gas liquids and 5 percent natural gas in the first nine months of 2012. During the third quarter and first nine months of 2012, we drilled 25 gross and 72 gross wells with seven rigs, with a total of 30 gross and 77 gross wells brought to sales in the third quarter and the first nine months of 2012. By the end of October 2012, we had reduced our operated rig count in the Bakken shale to five. We continue to focus on downspacing and development in the Three Forks area.

In the Anadarko Woodford shale, net sales volumes averaged 10 mboed and 7 mboed during the third quarter and first nine months of 2012 compared to 2 mboed and 2 mboed in the same periods of 2011. During the third quarter of 2012, eight gross wells were brought to sales, with 14 gross wells brought to sales in the first nine months of 2012. As announced in August, in response to the continued decline in natural gas liquids prices and low natural gas prices, we have reduced our rig count in the Anadarko Woodford play from six to two. Other areas of potential growth exist in Oklahoma and we are currently evaluating opportunities on legacy assets where the acreage is held by production. Future activity in these Oklahoma resource basins will be dependent upon the recovery of natural gas and natural gas liquids prices.

In the first quarter 2011, production operations in Libya were suspended. In the fourth quarter of 2011, limited production resumed and has increased during 2012 so that during the third quarter and first nine months of 2012, net sales volumes averaged 53 mboed and 51 mboed. We and our partners in the Waha concessions continue to assess the condition of our assets in Libya and uncertainty around sustained production and sales levels remains.

In June 2012, we submitted a plan for the development and operation of the Boyla field (PL 340) in the North Sea to the Norwegian Ministry of Petroleum and Energy, which was approved in October 2012. The Boyla field is located approximately 17 miles south of our operated Alvheim field. We hold a 65 percent working interest in the field. First production from Boyla is expected in the fourth quarter of 2014.

In the second quarter of 2012, we completed a four-day turnaround in Norway that was originally scheduled for 14 days in the third quarter. During the third quarter of 2012, we became operator of the Vilje field offshore Norway in which we own a 47 percent interest.

A 28-day turnaround began at our production operations in Equatorial Guinea on March 23, 2012. It was completed in April 2012, seven days ahead of schedule and below budget.

Our Ozona development in the Gulf of Mexico began production in December 2011. During the first quarter of 2012, production rates declined significantly and have remained below initial expectations. Accordingly, our reserve engineers performed an evaluation of our future production as well as our reserves which concluded in early April 2012. This resulted in a 2 million barrels of oil equivalent reduction in proved reserves and a $261 million impairment charge in the first quarter of 2012.

Exploration

The appraisal well on the Shenandoah prospect located on Walker Ridge Block 51 in the Gulf of Mexico, in which we have a 10 percent outside-operated working interest, is currently drilling. In the third quarter of 2012, we resumed drilling the exploration well on the Gulf of Mexico Innsbruck prospect on Mississippi Canyon Block 993 in which we hold a 45 percent operated working interest. Through September 30, 2012, our net costs related to the well were $71 million. The well has drilled through multiple horizons with no commercial hydrocarbons found as of November 6, 2012. We anticipate reaching total depth within the next few days at a total net cost, including asset retirement obligations and leasehold costs, of approximately $100 million.

In the second quarter of 2012, a Gunflint prospect appraisal well confirmed expected reservoir properties and continuity, establishing the commercial viability of the field. The Gunflint discovery is located on Mississippi Canyon Block 948 and we have a 15 percent outside-operated working interest in the prospect. During the second quarter of 2012, the well costs and related unproved property costs related to the Kilchurn well were charged to exploration expenses.

We continue exploratory drilling in Poland where we hold a 51 percent working interest in 10 operated concessions and a 100 percent working interest in one concession. We have drilled 4 exploratory wells and are currently drilling a fifth well. We have collected extensive data, including well logs and core samples, which are being evaluated. We plan to begin a sixth well by year end 2012 which should reach total depth in 2013.

In the Kurdistan Region of Iraq, we began drilling our first operated exploration well on the Harir block in July 2012 and plan to drill an operated exploration well on the Safen block in the first quarter of 2013. After the farm out discussed below, we have 45 percent working interests in both the Harir and Safen blocks. On the non-operated Atrush block, we participated in an appraisal well during the third quarter of 2012. Additionally, we participated in a non-operated well that commenced drilling on the Sarsang block in September 2012. We hold a 20 percent working interest in the Atrush block and a 25 percent working interest in the Sarsang block.

During the first quarter of 2012, on the Birchwood oil sands lease located in Alberta, Canada, we conducted a seismic survey and drilled six water wells. We also submitted a regulatory application for a proposed 12 thousand barrel per day (“mbbld”) steam assisted gravity drainage ("SAGD") project at Birchwood. Pending regulatory approval, project sanction is expected in 2014, with first oil projected in 2017. We have a 100 percent working interest in Birchwood.

Acquisitions and Dispositions

We continually evaluate ways to optimize our portfolio for profitable growth through acquisitions and dispositions, with a previously stated goal of divesting between $1.5 billion and $3 billion over the period of 2011 through 2013. To date, we have entered into agreements for approximately $1.1 billion in divestitures, of which more than $700 million have been completed. Included in the $1.1 billion noted above is the pending sale of our Alaska assets which is discussed below.

On November 1, 2012, we closed the acquisition of an additional 4,300 net acres in the core of the Eagle Ford shale at a transaction cost of approximately $232 million before closing adjustments. This acquisition increased our average working interest by 5 to 7 percent in four core areas of mutual interest, included wells producing 3 net mboed at closing, and added 40 net drilling locations to our inventory. The closing of this transaction combined with the acquisition of Paloma Partners II, LLC ("Paloma acquisition"), brings our acquisitions thus far in 2012 in the core of the play to almost 25,000 additional net acres at an approximate cost of $1 billion. The Paloma acquisition closed in August 2012 as discussed below. We now have approximately 230,000 net acres in the core of the Eagle Ford shale. The unproved property costs related to an additional 100,000 non-core net acres were impaired in the third quarter of 2012 as discussed below in Results of Operations.

In October 2012, we entered into an agreement to acquire a 20 percent non-operated working interest in the South Omo concession onshore Ethiopia with an effective date of August 17, 2012. An exploration well is anticipated to commence drilling in South Omo during the fourth quarter of 2012. Cash consideration for this transaction will be $40 million, before closing adjustments, with an additional payment of $10 million due upon declaration of a commercial discovery. We expect to close the transaction, subject to necessary Ethiopian government approvals, before the end of 2012.

We acquired approximately 20,000 net acres in the core of the Eagle Ford shale during the first nine months of 2012. The largest transaction was the acquisition of Paloma Partners II, LLC, which closed August 1, 2012 for cash consideration of $768 million. In addition to the over 17,100 net acres acquired, at closing 17 gross operated and 9 gross non-operated wells were producing an average of 9 net mboed, of which 70 percent was liquid hydrocarbons. Smaller transactions closed during the second quarter of 2012. See Note 6 to the consolidated financial statements for further details of the Paloma acquisition.

In the third quarter of 2012, we sold approximately 5,800 net undeveloped acres located outside the core of the Eagle Ford shale for proceeds of $9 million, recording a loss of $18 million.

In July 2012, we entered into an agreement to acquire outside-operated positions in two onshore exploration blocks in northwest Kenya. Upon closing the $35 million transaction in October 2012, we now hold a 50 percent working interest in Block 9, where an exploration well is currently planned in mid-2013, and a 15 percent working interest in Block 12A.

Also in July 2012, we agreed to farm out interests in the Harir and Safen blocks in the Kurdistan Region of Iraq. The transaction closed in October 2012 and we received cash proceeds of $140 million, so that we now have a 45 percent working interest and carry the KRG for an additional 11 percent in each of the two blocks.

In June 2012, we entered an agreement to acquire a 21 percent outside-operated working interest in the Diaba License G4-223 and its related permit onshore Gabon. The transaction closed in October 2012. The start of exploration drilling is expected in the first quarter of 2013.

During June 2012, we signed a new production sharing contract with the government of Equatorial Guinea for the exploration of Block A-12 offshore Bioko Island, located immediately west of our operated Alba Field. We have an 80 percent operated working interest in this block. The contract was ratified by the government in the third quarter of 2012. We also acquired an additional interest in Block D, bringing our working interest to 80 percent.

In May 2012, we executed agreements to relinquish our E&P segment's operatorship of and participating interests in the Bone Bay and Kumawa exploration licenses in Indonesia. As a result, we accrued and reported a $36 million loss on disposal of assets in the second quarter of 2012. Government ratification of the agreements was received during the third quarter of 2012, which released us from our obligations and further commitments related to these licenses, and we paid the amount accrued.

In April 2012, we entered agreements to sell our Alaska assets. One transaction closed in the second quarter of 2012 with proceeds and a net gain of $7 million. The remaining transaction, with a value of $375 million before closing adjustments, is currently under review by the Federal Trade Commission and the Alaska Attorney General's office, which could impact the closing of this transaction.

In January 2012, we closed on the sale of our interests in several Gulf of Mexico crude oil pipeline systems for proceeds of $206 million. This includes our equity method interests in Poseidon Oil Pipeline Company, L.L.C. and Odyssey Pipeline L.L.C., as well as certain other oil pipeline interests, including the Eugene Island pipeline system. A pretax gain of $166 million was recorded in the first quarter of 2012.

The above discussions include forward-looking statements with respect to the expected production in the Eagle Ford, Anadarko Woodford and Bakken plays, timing of first production from the Boyla field, anticipated drilling rig and drilling activity, the sale of our Alaska assets, possible increased recoverable resources from optimized well spacing in the Eagle Ford resource play, the expected closing of an agreement in Ethiopia, anticipated exploration activity in Ethiopia, Gabon, Poland and the Kurdistan Region of Iraq and the timing of the commencement of construction and first oil on the SAGD project. The projected asset dispositions through 2013 are based on current expectations, estimates, and projections and are not guarantees of future performance. Factors that could potentially affect the expected production in the Eagle Ford, Anadarko Woodford and Bakken plays, timing of first production from the Boyla field, exploratory activity in Ethiopia, Gabon, Poland and the Kurdistan Region of Iraq, possible increased recoverable resources from optimized well spacing in the Eagle Ford resource play and anticipated drilling rig and drilling activity include pricing, supply and demand for liquid hydrocarbons and natural gas, 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 thereto, and other geological, operating and economic considerations. The completion of the sale of our Alaska assets is subject to necessary government and regulatory approvals and customary closing conditions. The agreement in Ethiopia is subject to government approvals. The timing of commencement of construction and first oil on the SAGD project can be affected by delays in obtaining and conditions imposed by necessary government and third-party approvals, board approval, transportation logistics, availability of materials and labor, unforeseen hazards such as weather conditions, and the other risks associated with construction projects. 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 the our control and difficult to predict. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Oil Sands Mining

Our OSM operations consist of a 20 percent non-operated working interest in the Athabasca Oil Sands Project ("AOSP"). As announced in October 2012, we have engaged in discussions with respect to a potential sale of a portion of our 20 percent interest. Given the uncertainty of such a transaction, potential proceeds have not been included in our previously stated goal of divesting between $1.5 billion and $3 billion between 2011 and 2013.

Our net synthetic crude oil sales were 53 mbbld and 47 mbbld in the third quarter and first nine months of 2012 compared to 50 mbbld and 43 mbbld in the same periods of 2011. The upgrader expansion was completed and commenced operations in the third quarter of 2011 and subsequent periods' sales volumes have increased as a result. With production capacity at the AOSP now at 255,000 gross barrels per day, the focus will be on improving operating efficiencies and adding capacity through debottlenecking.

The Energy and Resources Conservation Board, Alberta’s primary energy regulator, conditionally approved the AOSP’s Quest Carbon Capture and Storage (“Quest CCS”) project in July 2012. The AOSP partners approved Quest CCS in the third quarter of 2012.

The above discussion contains forward-looking statements with regard to discussions with respect to a potential sale of a portion of our 20 percent interest in the AOSP. The potential sale of a portion of our interest in the AOSP is subject to successful negotiations and execution of definitive agreements. 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 difficult to predict. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Integrated Gas

LNG and methanol sales from Equatorial Guinea are conducted through equity method investees that purchase dry gas from our E&P assets in Equatorial Guinea. Our share of LNG sales totaled 7,065 metric tonnes per day (“mtd”) for the third quarter and 6,277 mtd for the first nine months of 2012 compared to 6,935 mtd and 7,121 mtd in the same periods of 2011. For the first nine months, LNG sales volumes are below the prior year due to a turnaround in the second quarter of 2012 at the facility in Equatorial Guinea, but primarily because the first nine months of 2011 also included LNG sales from Alaska, which ceased when our interest in that production facility was sold in the third quarter of 2011.

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 benchmark crude oil and natural gas price averages in the third quarter and first nine months of 2012 compared to the same periods in 2011.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Benchmark	2012	2011	2012	2011
WTI crude oil (Dollars per barrel)	$92.20	$89.54	$96.16	$95.47
Brent (Europe) crude oil (Dollars per barrel)	$109.61	$113.46	$112.17	$111.93
Henry Hub natural gas (Dollars per million British thermal units ("mmbtu"))[(a)]	$2.81	$4.19	$2.59	$4.16

[(a)] Settlement date average.

Average WTI crude oil benchmark prices increased 3 percent in the third quarter of 2012 compared to the same quarter of 2011. Our international crude oil production is relatively sweet and a majority is sold in relation to the Brent crude oil benchmark, which was 3 percent lower in the third quarter of 2012 than the same quarter of 2011. Both crude benchmarks were relatively flat on average when comparing the nine-month periods of 2012 and 2011.

Our domestic crude oil production was about 35 percent sour in the third quarter and 42 percent sour in the first nine months of 2012 compared to 64 percent and 62 percent in the same periods of 2011. Reduced production from the Gulf of Mexico and increased onshore production from the Bakken and Eagle Ford shale plays contributed to the lower sour crude percentage in 2012. 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.

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. Average Henry Hub settlement prices for natural gas were lower for the third quarter and first nine months of 2012 compared to the same periods of the prior year. A decline in average settlement date Henry Hub natural gas prices began in September 2011 and continued into 2012. Although prices have stabilized recently, they have not increased appreciably.

Our other major natural gas-producing regions are Europe and Equatorial Guinea. Natural gas prices in Europe have been higher than in the U.S. in recent periods. In the case of Equatorial Guinea, our natural gas sales are subject to term contracts, making realized prices in these areas less volatile. The natural gas sales from Equatorial Guinea are 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 ("WCS"). In 2012, the WCS discount from WTI has increased, bringing down our average price realizations. Output mix can be impacted by operational problems or planned unit outages at the mines 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, making per unit costs 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 2012 and 2011:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Benchmark	2012	2011	2012	2011
WTI crude oil (Dollars per barrel)	$92.20	$89.54	$96.16	$95.47
Western Canadian Select (Dollars per barrel)[a]	$70.49	$72.14	$74.21	$76.10
AECO natural gas sales index (Dollars per mmbtu)[b]	$2.27	$3.70	$2.03	$3.86

[a] Monthly pricing based upon average WTI adjusted for differentials unique to western Canada.

[b] Monthly average AECO day ahead index.

Integrated Gas

We have a 60 percent ownership in a production facility in Equatorial Guinea, which sells LNG under a long-term contract principally based upon Henry Hub natural gas prices.

We own a 45 percent interest in a methanol plant located in Equatorial Guinea. Methanol demand has a direct impact on the plant's earnings. Because global demand for methanol is rather limited, changes in the supply-demand balance can have a significant impact on sales prices. The plant capacity of 1.1 million tonnes is about 2 percent of 2011 estimated 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 in the third quarter of 2012 was 33 percent higher than in the same period of 2011 primarily due to the previously discussed resumption of our operations in Libya. The effective tax rate was 74 percent in the third quarter of 2012 compared to 69 percent in the third quarter of 2011, with the increase related to higher income from continuing operations in higher tax jurisdictions, primarily Libya.

Consolidated income from continuing operations before income taxes in the first nine months of 2012 was 40 percent higher than in the same period of 2011 primarily due to increased income in Libya. As a result of increased income from continuing operations before tax in higher tax jurisdictions, primarily Norway and Libya, the effective tax rate was 72 percent for the first nine months of 2012 compared to 64 percent for the same period of 2011.

Revenues are summarized by segment in the following table:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2012	2011	2012	2011
E&P	$3,519	$3,212	$10,327	$9,788
OSM	470	427	1,184	1,180
IG	—	16	—	93
Segment revenues	3,989	3,655	11,511	11,061
Unrealized gain on crude oil derivative instruments	45	—	45	—
Elimination of intersegment revenues	—	(6)	—	(47)
Total revenues	$4,034	$3,649	$11,556	$11,014

E&P segment revenues increased $307 million in the third quarter and $539 million in the first nine months of 2012 from the comparable prior-year periods. Included in our E&P segment are supply optimization activities which include the purchase of commodities from third parties for resale. Supply optimization serves to aggregate volumes in order to satisfy transportation commitments and to achieve flexibility within product types and delivery points. Volumes associated with supply optimization have been decreasing in 2012 due to market dynamics and related commodity prices have also been lower in 2012. See the Cost of revenues discussion as revenues from supply optimization approximate the related costs.

Revenues from the sale of our U.S. production are higher in the third quarter and first nine months of 2012 primarily as a result of increased liquid hydrocarbon sales volumes from our U.S. shale plays. Lower liquid hydrocarbon and natural gas realizations partially offset the volume impact. The following table gives details of net sales and average realizations of our U.S. operations.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
United States Operating Statistics				
Net liquid hydrocarbon sales (mbbld) [(a)]	111	69	98	73
Liquid hydrocarbon average realizations (per bbl) [(b)]	$83.80	$88.89	$86.98	$91.53
Net natural gas sales (mmcfd)	366	296	343	326
Natural gas average realizations (per mcf)[(b)]	$3.61	$4.85	$3.73	$5.04

(a)Includes crude oil, condensate and natural gas liquids.

(b)Excludes gains and losses on derivative instruments

Revenues from our international operations are higher in the third quarter and first nine months of 2012 primarily as a result of the previously discussed resumption of liquid hydrocarbon sales from Libya. Higher average liquid hydrocarbon realizations during the third quarter and first nine months of 2012 also contributed to the revenue increase for both periods.

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,	
	2012	2011	2012	2011
International Operating Statistics				
Net liquid hydrocarbon sales (mbbld)[(a)]				
Europe	94	108	97	102
Africa	88	34	73	44
Total International	182	142	170	146
Liquid hydrocarbon average realizations (per bbl)[(b)]				
Europe	$112.34	$117.05	$115.73	$115.91
Africa	98.65	63.51	97.00	75.38
Total International	$105.71	$104.24	$107.69	$103.75
Net natural gas sales (mmcfd)				
Europe[(c)]	100	79	102	92
Africa	485	453	434	440
Total International	585	532	536	532
Natural gas average realizations (per mcf)[(b)]				
Europe	$10.10	$9.81	$10.05	$10.07
Africa	0.63	0.24	0.39	0.24
Total International	$2.25	$1.67	$2.23	$1.95

(a) Includes crude oil, condensate and natural gas liquids. The amounts correspond with the basis for fiscal settlements with governments, representing equity tanker liftings and direct deliveries of liquid hydrocarbons.

(b) Excludes gains and losses on derivative instruments.

(c) Includes natural gas acquired for injection and subsequent resale of 18 mmcfd and 16 mmcfd for the third quarters of 2012 and 2011, and 16 mmcfd and 15 mmcfd for the first nine months of 2012 and 2011.

OSM segment revenues increased $43 million in the third quarter and $4 million in the first nine months of 2012 compared to the same periods of 2011. The upgrader expansion was completed and commenced operations in the third quarter of 2011, resulting in higher sales volumes in both periods. However, an increase in the discount of WCS to WTI resulted in the decreases in average realizations during the third quarter and first nine months of 2012, partially offsetting the positive volume variance.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
OSM Operating Statistics				
Net synthetic crude oil sales (mbbld) [(a)]	53	50	47	43
Synthetic crude oil average realizations (per bbl)	$81.13	$87.29	$83.58	$90.91

(a) Includes blendstocks.

IG segment revenues decreased $16 million in the third quarter and $93 million in the first nine months of 2012 compared to the same periods of 2011. Sales of LNG from our Alaska operations ceased in the third quarter of 2011 when we sold our interest in this production facility.

Unrealized gain on crude oil derivative instruments is included in total revenues but not segment revenues. In the third quarter and first nine months of 2012, the net unrealized gain on crude oil derivative instruments was $45 million and there was no comparable derivative activity in similar periods of 2011. See Note 14 to the consolidated financial statements and Item 3. Quantitative and Qualitative Disclosures About Market Risk for additional information about our derivative positions.

Income from equity method investments decreased $100 million in the first nine months of 2012 from the comparable prior-year period, primarily due to lower natural gas prices and turnarounds early in 2012 at our facilities in Equatorial Guinea. Also, in January 2012, we sold our equity investments in several Gulf of Mexico crude oil pipelines.

Net gain (loss) on disposal of assets in the third quarter of 2012 primarily reflects an $18 million loss on the sale of undeveloped acreage outside the core of the Eagle Ford shale resource play. The net gain on disposal of assets in the first nine months of 2012 consists primarily of the $166 million gain on the sale of our interests in several Gulf of Mexico crude oil pipeline systems, reduced by the $36 million loss on the assignment of our Bone Bay and Kumawa exploration licenses in Indonesia and the $18 million loss on the Eagle Ford acreage. See Note 7 to the consolidated financial statements for information about these dispositions.

Cost of revenues decreased $304 million and $666 million in the third quarter and first nine months of 2012 from the comparable periods of 2011 primarily due to our supply optimization activities. Volumes associated with supply optimization have been decreasing in 2012 due to market dynamics and related commodity prices have also been lower in 2012. Comparatively, costs related to supply optimization were lower by $438 million for the third quarter and by $677 million for the first nine months of 2012. Excluding the impact of supply optimization activities, E&P segment operating expenses have increased in proportion to our increased production from U.S. shale plays. Additionally, Integrated Gas segment costs are lower in 2012 due to the sale of our interest in the Alaska LNG facility in the third quarter of 2011.

Depreciation, depletion and amortization ("DD&A") increased $108 million in the third quarter and $63 million in the first nine months of 2012 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 in sales volumes generally result in similar changes in DD&A. 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. Lower U.S. and International E&P DD&A rates in the third quarter and first nine months of 2012 compared to the same periods in 2011 partially offset the impact of higher sales volumes in those periods. Also, there was no depletion of our Alaska assets in the second and third quarters of 2012 because they are held for sale. The following table provides DD&A rates for our E&P and OSM segments.

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ per boe)	2012	2011	2012	2011
DD&A rate				
E&P Segment				
United States	$23	$24	$23	$26
International	8	10	9	10
OSM Segment	$6	$6	$6	$6

Impairments in the first nine months of 2012 related primarily to the Ozona development in the Gulf of Mexico. Impairments in the first nine months of 2011 related primarily to the Droshky development in the Gulf of Mexico and an intangible asset for an LNG delivery contract at Elba Island. See Note 13 to the consolidated financial statements for information about these impairments.

General and administrative expenses increased $35 million in the third quarter and $18 million in the first nine months of 2012 compared to the same periods in 2011. The third quarter of 2012 includes pension settlement expense of $34 million. See Note 9 to the consolidated financial statements for information about the pension settlement. The cost increase for the nine-month period of 2012 is lower because 2011 included higher incentive compensation expense due to the increase in Marathon's stock price in the period leading up to the spin-off.

Exploration expenses were higher in the third quarter of 2012 than in the same quarter of 2011, primarily due to larger unproved property impairments. The third quarter of 2012 included $51 million related to unproved property impairments associated with approximately 100,000 net non-core acres in the Eagle Ford shale. Exploration expenses were lower in the first nine months of 2012 than in the previous year, primarily due to dry wells in the Gulf of Mexico, Norway and Indonesia in 2011 compared to one dry Gulf of Mexico well plus various U.S. onshore dry wells in 2012; however, higher unproved property impairments in the Marcellus shale, Eagle Ford shale and Indonesia in 2012 partially offset this decrease. Geological and geophysical ("G&G") costs increased in the nine months of 2012 primarily related to activity in the Kurdistan Region of Iraq and the seismic survey on our Birchwood oil sands in-situ lease.

The following table summarizes the components of exploration expenses.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2012	2011	2012	2011
Unproved property impairments	$79	$16	$149	$59
Dry well costs	35	31	138	252
G&G	24	39	94	67
Other	38	43	110	126
Total exploration expenses	$176	$129	$491	$504

Net interest and other increased $23 million and $98 million in the third quarter and first nine months of 2012 from the comparable periods of 2011. Foreign currency gains were lower in the third quarter of 2012 than in the same quarter of 2011. In addition, capitalized interest has been lower in both periods of 2012.

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

Provision for income taxes increased $381 million and $1,180 million in the third quarter and first nine months of 2012 from the comparable periods of 2011 primarily due to the increase in pretax income in high tax rate jurisdictions, including the impact of the previously discussed resumption of sales in Libya in the first quarter of 2012.

The effective income tax rate is influenced by a variety of factors including the geographic and functional sources of income and the relative magnitude of these sources of income. 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" in Note 8 to the consolidated financial statements.

Our effective tax rate in the first nine months of 2012 was 72 percent. This rate is higher than the U.S. statutory rate of 35 percent primarily due to earnings from foreign jurisdictions, primarily Norway and Libya, where the tax rates are in excess of the U.S. statutory rate. An increase in earnings and associated taxes from foreign jurisdictions, primarily Norway, as compared to prior periods caused an increase in our valuation allowance on current year foreign tax credits. In Libya, where the statutory tax rate is in excess of 90 percent, limited production resumed in the fourth quarter of 2011 and liquid hydrocarbon sales resumed in the first quarter of 2012. A reliable estimate of 2012 annual ordinary income from our Libyan operations cannot be made and the range of possible scenarios when including ordinary income from our Libyan operations in the worldwide annual effective tax rate calculation demonstrates significant variability. As such, for the first nine months of 2012, an estimated annual effective tax rate was calculated excluding Libya and applied to consolidated ordinary income excluding Libya and the tax provision applicable to Libyan ordinary income was recorded as a discrete item in the period. Excluding Libya, the effective tax rate would be 64 percent for the first nine months of 2012.

Our effective tax rate in the first nine months of 2011 was 64 percent which is higher than the U.S. statutory tax rate of 35 percent primarily due to earnings from foreign jurisdictions where the tax rates are in excess of the U.S. statutory rate and the valuation allowance recorded against 2011 foreign tax credits. In addition, in the second quarter of 2011, we recorded a deferred tax charge related to an internal restructuring of our international subsidiaries.

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

Segment Results

Segment income is summarized in the following table.

(In millions)	Three Months Ended September 30, 2012	2011	Nine Months Ended September 30, 2012	2011
E&P				
United States	$110	$81	$289	$237
International	376	249	1,091	1,362
E&P segment	486	330	1,380	1,599
OSM	65	92	157	193
IG	39	55	56	158
Segment income	590	477	1,593	1,950
Items not allocated to segments, net of income taxes:				
Corporate and other unallocated items	(158)	(56)	(267)	(209)
Unrealized gain on crude oil derivative instruments	29	—	29	—
Gain (loss) on dispositions	(11)	(1)	72	23
Impairments	—	—	(167)	(195)
Loss on early extinguishment of debt	—	—	—	(176)
Tax effect of subsidiary restructuring	—	—	—	(122)
Deferred income tax items	—	(15)	—	(65)
Water abatement - Oil Sands	—	—	—	(48)
Income from continuing operations	450	405	1,260	1,158
Discontinued operations	—	—	—	1,239
Net income	$450	$405	$1,260	$2,397

United States E&P income increased $29 million in the third quarter and increased $52 million in the first nine months of 2012 compared to the same periods of 2011. The income increase in both periods was primarily the result of higher liquid hydrocarbon sales volumes as previously discussed, partially offset by lower liquid hydrocarbon realizations and the impact of increased production operations on DD&A and operating expenses. In addition, exploration expenses were higher primarily due to higher unproved property impairments.

International E&P income increased $127 million in the third quarter and decreased $271 million in the first nine months of 2012 compared to the same periods of 2011. Segment income, before taxes, increased in both periods primarily due to the previously discussed higher liquid hydrocarbon sales volumes and realizations, partially offset by increased operating costs. As previously discussed, increased income before tax in higher tax jurisdictions resulted in a higher effective tax rate in the first nine months of 2012 compared to the same period of 2011.

OSM segment income decreased $27 million and $36 million in the third quarter and first nine months of 2012. As previously discussed, lower synthetic crude oil price realizations were the primary reason for the decrease in income. This was partially offset by decreased costs on a per unit basis and higher sales volumes.

IG segment income decreased $16 million and $102 million in the third quarter and first nine months of 2012 compared to the same periods of 2011 primarily due to lower natural gas prices and turnarounds early in 2012 at our facilities in Equatorial Guinea. In addition, LNG sales volumes are lower in the first nine months of 2012 due to the sale of our interest in the Alaska LNG facility in the third quarter of 2011.

Critical Accounting Estimates

There have been no changes to our critical accounting estimates subsequent to December 31, 2011.

Cash Flows and Liquidity

Cash Flows

Net cash provided by continuing operations was $2,812 million in the first nine months of 2012, compared to $4,400 million in the first nine months of 2011 primarily reflecting the impact of lower U.S. liquid hydrocarbon and natural gas prices on operating income and higher cash tax payments. See Note 17 to the consolidated financial statements for amounts of the cash tax payments.

Net cash used in investing activities totaled $4,031 million in the first nine months of 2012, compared to $2,118 million related to continuing operations in the first nine months of 2011. Significant investing activities are additions to property, plant and equipment and disposal of assets. In the first nine months of 2012, most of the additions were in the E&P segment with continued spending on U.S. unconventional resource plays, particularly the Eagle Ford shale. This compares to additions in the first nine months of 2011 which also included spending on U.S. unconventional resource plays, though at a lower level, and drilling in Norway, Indonesia and the Kurdistan Region of Iraq. In the first nine months of 2012, expenditures for acquisitions totaled $806 million primarily related to acquiring additional Eagle Ford shale properties. Deposits totaling $120 million were paid in the first nine months of 2011 related to the Eagle Ford shale acreage acquisitions that closed later that year.

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

Net cash provided by financing activities was $1,385 million in the first nine months of 2012, compared to net cash used in financing activities related to continuing operations of $5,098 million in the first nine months of 2011. During the first nine months of 2012, we drew a net $1,839 million under our commercial paper program, retired $23 million principal amount of debt before it was due and repaid $88 million of debt upon its maturity. During the first nine months of 2011, we retired $2.5 billion aggregate principal amount of our debt before it was due and distributed $1.6 billion to Marathon Petroleum Corporation in connection with the spin-off of the downstream business. Dividends paid were a significant use of cash in both periods.

Liquidity and Capital Resources

Our main sources of liquidity are cash and cash equivalents, internally generated cash flow from operations, the issuance of notes, our committed revolving credit facility, and sales of non-strategic assets. Our working capital requirements are supported by these sources and we may issue commercial paper backed by our $2.5 billion revolving credit facility to meet short-term cash requirements. We issued $10.4 billion and repaid $8.6 billion of commercial paper in the first nine months of 2012 leaving a balance of $1.8 billion outstanding at September 30, 2012. After September 30, 2012, we continued to utilize our sources of liquidity, including additional issuances of commercial paper and notes as discussed below, to fund working capital requirements. Because of the alternatives available to us as discussed above 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, and other amounts that may ultimately be paid in connection with contingencies.

Capital Resources

At September 30, 2012, we had no borrowings against our revolving credit facility, described below, and $1.8 billion in commercial paper outstanding under our U.S. commercial paper program that is backed by the revolving credit facility.

On October 29, 2012, we issued $1 billion aggregate principal amount of senior notes bearing interest at 0.9 percent with a maturity date of November 1, 2015 and $1 billion aggregate principal amount of senior notes bearing interest at 2.8 percent with a maturity date of November 1, 2022. Interest on the senior notes is payable semi-annually beginning May 1, 2013. The proceeds are being used to pay off commercial paper and for general corporate purposes.

In April 2012, we terminated our $3.0 billion five-year revolving credit facility and replaced it with a new $2.5 billion unsecured five-year revolving credit facility (the “Credit Facility”). The Credit Facility matures in April 2017 but allows us to request two one-year extensions. It contains an option to increase the commitment amount by up to an additional $1.0 billion, subject to the consent of any increasing lenders, and includes sub-facilities for swing-line loans and letters of credit up to an aggregate amount of $100 million and $500 million, respectively. Fees on the unused commitment of each lender range from 10 basis points to 25 basis points per year depending on our credit ratings. Borrowings under the Credit Facility bear interest, at our option, at either (a) an adjusted London Interbank Offered Rate ("LIBOR") plus a margin ranging from 87.5 basis points to 162.5 basis points per year depending on our credit ratings or (b) the Base Rate plus a margin ranging from 0.0 basis points to 62.5 basis points depending on our credit ratings. Base Rate is defined as a per annum rate equal to the greatest of (a) the prime rate, (b) the federal funds rate plus one-half of one percent and (c) LIBOR for a one-month interest period plus 1 percent.

The agreement contains a covenant that requires our ratio of total debt to total capitalization not to exceed 65 percent as of the last day of each fiscal quarter. If an event of default occurs, the lenders may terminate the commitments under the Credit Facility and require the immediate repayment of all outstanding borrowings and the cash collateralization of all outstanding letters of credit under the Credit Facility.

We have a universal shelf registration statement filed with the Securities and Exchange Commission under which we, as a well-known seasoned issuer, have the ability to issue and sell an indeterminate amount of various types of debt and equity securities.

Our cash-adjusted debt-to-capital ratio (total debt-minus-cash to total debt-plus-equity-minus-cash) was 25 percent at September 30, 2012, compared to 20 percent at December 31, 2011.

(In millions)	September 30, 2012	December 31, 2011
Commercial paper	$1,839	$—
Long-term debt due within one year	183	141
Long-term debt	4,518	4,674
Total debt	6,540	4,815
Cash	671	493
Equity	$18,064	$17,159
Calculation:		
Total debt	$6,540	$4,815
Minus cash	671	493
Total debt minus cash	5,869	4,322
Total debt	6,540	4,815
Plus equity	18,064	17,159
Minus cash	671	493
Total debt plus equity minus cash	$23,933	$21,481
Cash-adjusted debt-to-capital ratio	25 %	20 %

Capital Requirements

On October 31, 2012, our Board of Directors approved a dividend of 17 cents per share for the third quarter of 2012, payable December 10, 2012 to stockholders of record at the close of business on November 21, 2012.

In October and early November 2012, we paid $264 million for closed acquisition transactions.

In the first quarter of 2012, we increased our 2012 capital, investment and exploration budget, excluding acquisition costs, from $4.8 billion to $5.0 billion, of which $4.6 billion will be used for capital expenditures. The increase reflects development plans for the additional acreage acquired in the Eagle Ford shale and other adjustments.

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 above discussions also contain forward-looking statements about our 2012 capital, investment and exploration budget. 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 liquid hydrocarbons 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 contractual cash obligations to make future payments under existing contracts as of September 30, 2012.

(In millions)	Total	2012	2013-2014	2015-2016	Later Years
Short and long-term debt (excludes interest)	$6,504	$1,874	$250	$69	$4,311
Lease obligations	281	39	80	65	97
Purchase obligations:					
Oil and gas activities[a]	993	351	505	59	78
Service and materials contracts[b]	909	45	227	131	506
Transportation and related contracts	1,301	63	317	190	731
Drilling rigs and fracturing crews	894	139	730	25	—
Other	234	57	93	27	57
Total purchase obligations	4,331	655	1,872	432	1,372
Other long-term liabilities reported in the consolidated balance sheet[c]	1,122	174	272	253	423
Total contractual cash obligations[d]	$12,238	$2,742	$2,474	$819	$6,203

(a) Oil and gas activities include contracts to acquire property, plant and equipment and commitments for oil and gas exploration such as costs related to contractually obligated exploratory work programs that are expensed immediately.

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

(c) Primarily includes obligations for pension and other postretirement benefits including medical and life insurance, which we have estimated through 2021. Also includes amounts for uncertain tax positions.

(d) This table does not include the estimated discounted liability for dismantlement, abandonment and restoration costs of oil and gas properties of $1,516 million.

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.

There have been no significant changes to our environmental matters subsequent to December 31, 2011.

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.

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 probable loss (or range of loss) can be made for this lawsuit at this time.

34

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 2011 Annual Report on Form 10-K.

In August 2012, we entered crude oil derivatives related to a portion of our forecast U.S. E&P crude oil sales through December 31, 2013. 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.

Sensitivity analysis of the incremental effects on income from operations ("IFO") of hypothetical 10 percent and 25 percent increases and decreases in commodity prices on our open commodity derivative instruments, by contract type as of September 30, 2012 is provided in the following table.

	Incremental Change in IFO from a Hypothetical Price Increase of		Incremental Change in IFO from a Hypothetical Price Decrease of	
	10%	25%	10%	25%
Crude oil				
Swaps	$(207)	$(519)	$207	$519
Option Collars	(105)	(277)	103	275
Total crude oil	(312)	(796)	310	794
Natural gas				
Futures	(1)	(2)	1	2
Total natural gas	(1)	(2)	1	2
Total	$(313)	$(798)	$311	$796

Sensitivity analysis of the projected incremental effect of a hypothetical 10 percent change in interest rates on financial assets and liabilities as of September 30, 2012 is provided in the following table.

(In millions)	Fair Value	Incremental Change in Fair Value
Financial assets (liabilities): [a]		
Interest rate swap agreements	$22 [b]	$1
Long-term debt, including amounts due within one year	$(5,639) [b]	$(206)

(a) Fair values of cash and cash equivalents, receivables, commercial paper, accounts payable and accrued interest approximate carrying value and are relatively insensitive to changes in interest rates due to the short-term maturity of the instruments. Accordingly, these instruments are excluded from the table.

(b) Fair value was based on market prices where available, or current borrowing rates for financings with similar terms and maturities.

The aggregate cash flow effect on foreign currency derivative contracts of a hypothetical 10 percent change in exchange rates at September 30, 2012 would be $69 million.

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.

In 2012, we began a project to update our existing ERP system. The project includes implementation of a new general ledger, consolidations system and reporting tools. This project is currently in testing phases and we expect full implementation in the first half of 2013. We believe that controls over project development and implementation are adequate to assure there will be no material effect, or a reasonable likelihood of a material effect, on our internal control over financial reporting.

During the quarter ended September 30, 2012, 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)	2012	2011	2012	2011
Segment Income				
Exploration and Production				
United States	$110	$81	$289	$237
International	376	249	1,091	1,362
E&P segment	486	330	1,380	1,599
Oil Sands Mining	65	92	157	193
Integrated Gas	39	55	56	158
Segment income	590	477	1,593	1,950
Items not allocated to segments, net of income taxes	(140)	(72)	(333)	(792)
Income from continuing operations	450	405	1,260	1,158
Discontinued operations[a]	—	—	—	1,239
Net income	$450	$405	$1,260	$2,397
Capital Expenditures[b]				
Exploration and Production				
United States	$1,046	$502	$2,891	$1,407
International	228	182	568	694
E&P segment	1,274	684	3,459	2,101
Oil Sands Mining	41	36	136	236
Integrated Gas	1	1	2	2
Corporate	23	7	82	37
Total	$1,339	$728	$3,679	$2,376
Exploration Expenses				
United States	$132	$75	$369	$280
International	44	54	122	224
Total	$176	$129	$491	$504

(a) The spin-off of our downstream business was completed on June 30, 2011, and has been reported as discontinued operations in 2011.

(b) Capital expenditures include changes in accruals.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
E&P Operating Statistics				
Net Liquid Hydrocarbon Sales (mbbld)				
United States	111	69	98	73
Europe	94	108	97	102
Africa	88	34	73	44
Total International	182	142	170	146
Worldwide	293	211	268	219
Net Natural Gas Sales (mmcfd)				
United States	366	296	343	326
Europe[c]	100	79	102	92
Africa	485	453	434	440
Total International	585	532	536	532
Worldwide	951	828	879	858
Total Worldwide Sales (mboed)	452	349	414	362
Average Realizations [d]				
Liquid Hydrocarbons (per bbl)				
United States	$83.80	$88.89	$86.98	$91.53
Europe	$112.34	$117.05	$115.73	$115.91
Africa	$98.65	$63.51	$97.00	$75.38
Total International	$105.71	$104.24	$107.69	$103.75
Worldwide	$97.40	$99.24	$100.10	$99.68
Natural Gas (per mcf)				
United States	$3.61	$4.85	$3.73	$5.04
Europe	$10.10	$9.81	$10.05	$10.07
Africa[e]	$0.63	$0.24	$0.39	$0.24
Total International	$2.25	$1.67	$2.23	$1.95
Worldwide	$2.77	$2.81	$2.81	$3.12
OSM Operating Statistics				
Net Synthetic Crude Oil Sales (mbbld) [f]	53	50	47	43
Synthetic Crude Oil Average Realizations (per bbl)[d]	$81.13	$87.29	$83.58	$90.91
IG Operating Statistics				
Net Sales (mtd) [g]				
LNG	7,065	6,935	6,277	7,121
Methanol	1,146	1,366	1,242	1,310

(c) Includes natural gas acquired for injection and subsequent resale of 18 mmcfd and 16 mmcfd for the third quarters of 2012 and 2011, and 16 mmcfd and 15 mmcfd for the first nine months of 2012 and 2011.

(d) Excludes gains and losses on derivative instruments.

(e)

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.

(f) Includes blendstocks.

(g) Includes both consolidated sales volumes and our share of the sales volumes of equity method investees in 2011. LNG sales from Alaska, conducted through a consolidated subsidiary, ceased when these operations were sold in the third quarter of 2011. 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. There have been no significant changes in legal or environmental proceedings during the first nine months of 2012.

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 2011 Annual Report on Form 10-K.

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

The following table provides information about purchases by Marathon Oil during the quarter ended September 30, 2012, of equity securities that are registered by Marathon Oil pursuant to Section 12 of the Securities Exchange Act of 1934.

Period	Column (a) Total Number of Shares Purchased [(a)(b)]	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)]
07/01/12 – 07/31/12	12,285	$25.62	—	$1,780,609,536
08/01/12 – 08/31/12	143,642	$27.59	—	$1,780,609,536
09/01/12 – 09/30/12	38,963	$28.43	—	$1,780,609,536
Total	194,890	$27.63	—	

(a) 162,184 shares of restricted stock were delivered by employees to Marathon Oil, upon vesting, to satisfy tax withholding requirements.

(b) In September 2012, 32,706 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, 2012, 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. Of this total, 66 million shares had been acquired at a cost of $2,922 million prior to the spin-off of the downstream business.

Item 4. Mine Safety Disclosures

Not applicable.

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
3.1	Amended By-laws of Marathon Oil Corporation, effective January 1, 2013.					X	
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 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 pursuant to 18 U.S.C. Section 1350.					X	
101.INS	XBRL Instance Document.					X	
101.SCH	XBRL Taxonomy Extension Schema.					X	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.					X	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.					X	
101.DEF	XBRL Taxonomy Extension Definition Linkbase.					X	
101.LAB	XBRL Taxonomy Extension Label 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 7, 2012		MARATHON OIL CORPORATION
	By:	/s/ Michael K. Stewart
		Michael K. Stewart
		Vice President, Finance and Accounting,
		Controller and Treasurer