MARATHON OIL CORP
Form 10-Q
August 08, 2013

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 June 30, 2013

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 R No £

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

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

Large accelerated filer	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 709,671,894 shares of Marathon Oil Corporation common stock outstanding as of July 31, 2013.

MARATHON OIL CORPORATION

Form 10-Q

Quarter Ended June 30, 2013

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

Part I - Financial Information
Item 1. Financial Statements

MARATHON OIL CORPORATION
Consolidated Statements of Income (Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions, except per share data)	2013	2012	2013	2012
Revenues and other income:				
Sales and other operating revenues, including related party	$3,419	$2,975	$6,859	$5,919
Marketing revenues	499	757	929	1,606
Income from equity method investments	77	60	195	138
Net gain (loss) on disposal of assets	(107)	(28)	2	138
Other income	10	20	19	23
Total revenues and other income	3,898	3,784	8,004	7,824
Costs and expenses:				
Production	614	485	1,192	987
Marketing, including purchases from related parties	495	755	924	1,609
Other operating	86	107	197	199
Exploration	133	172	598	307
Depreciation, depletion and amortization	738	580	1,485	1,154
Impairments	—	1	38	263
Taxes other than income	93	55	177	123
General and administrative	164	154	338	313
Total costs and expenses	2,323	2,309	4,949	4,955
Income from operations	1,575	1,475	3,055	2,869
Net interest and other	(71)	(57)	(143)	(107)
Income before income taxes	1,504	1,418	2,912	2,762
Provision for income taxes	1,078	1,025	2,103	1,952
Net income	$426	$393	$809	$810
Per Share Data				
Net Income:				
Basic	$0.60	$0.56	$1.14	$1.15
Diluted	$0.60	$0.56	$1.14	$1.14
Dividends paid	$0.17	$0.17	$0.34	$0.34
Weighted average shares:				
Basic	710	706	709	705
Diluted	714	709	713	709

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

MARATHON OIL CORPORATION
Consolidated Statements of Comprehensive Income (Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2013	2012	2013	2012
Net income	$426	$393	$809	$810
Other comprehensive income (loss)				
Postretirement and postemployment plans				
Change in actuarial loss and other	133	(3)	146	10
Income tax (provision) benefit on postretirement and postemployment plans	(49)	1	(54)	(4)
Postretirement and postemployment plans, net of tax	84	(2)	92	6
Foreign currency translation and other				
Unrealized loss	(3)	(1)	(4)	—
Income tax benefit on foreign currency translation and other	1	—	1	—
Foreign currency translation and other, net of tax	(2)	(1)	(3)	—
Other comprehensive income (loss)	82	(3)	89	6
Comprehensive income	$508	$390	$898	$816

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)	June 30, 2013	December 31, 2012
Assets		
Current assets:		
Cash and cash equivalents	$246	$684
Receivables	2,443	2,418
Inventories	368	361
Other current assets	224	299
Total current assets	3,281	3,762
Equity method investments	1,244	1,279
Property, plant and equipment, less accumulated depreciation, depletion and amortization of $20,639 and $19,266	27,457	28,272
Goodwill	499	525
Other noncurrent assets	2,567	1,468
Total assets	$35,048	$35,306
Liabilities		
Current liabilities:		
Commercial paper	$—	$200
Accounts payable	2,152	2,324
Payroll and benefits payable	137	217
Accrued taxes	1,397	1,983
Other current liabilities	254	173
Long-term debt due within one year	68	184
Total current liabilities	4,008	5,081
Long-term debt	6,428	6,512
Deferred tax liabilities	2,406	2,432
Defined benefit postretirement plan obligations	739	856
Asset retirement obligations	2,039	1,749
Deferred credits and other liabilities	407	393
Total liabilities	16,027	17,023
Commitments and contingencies		
Stockholders' Equity		
Preferred stock – no shares issued or 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 or outstanding (no par value, 29 million shares authorized)	—	—
Held in treasury, at cost – 61 million and 63 million shares	(2,477)	(2,560)
Additional paid-in capital	6,614	6,616
Retained earnings	14,458	13,890
Accumulated other comprehensive loss	(344)	(433)
Total equity	19,021	18,283
Total liabilities and stockholders' equity	$35,048	$35,306

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

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MARATHON OIL CORPORATION
Consolidated Statements of Cash Flows (Unaudited)

	Six Months Ended June 30,	
(In millions)	2013	2012
Increase (decrease) in cash and cash equivalents		
Operating activities:		
Net income	$809	$810
Adjustments to reconcile net income to net cash provided by operating activities:		
Deferred income taxes	113	75
Depreciation, depletion and amortization	1,485	1,154
Impairments	38	263
Pension and other postretirement benefits, net	34	(22)
Exploratory dry well costs and unproved property impairments	494	174
Net gain on disposal of assets	(2)	(138)
Equity method investments, net	—	7
Changes in:		
Current receivables	17	(107)
Inventories	(16)	(18)
Current accounts payable and accrued liabilities	(651)	(450)
All other operating, net	75	(6)
Net cash provided by operating activities	2,396	1,742
Investing activities:		
Additions to property, plant and equipment	(2,676)	(2,181)
Disposal of assets	333	218
Investments - return of capital	29	21
All other investing, net	15	(59)
Net cash used in investing activities	(2,299)	(2,001)
Financing activities:		
Commercial paper, net	(200)	550
Debt issuance costs	—	(9)
Debt repayments	(148)	(111)
Dividends paid	(241)	(240)
All other financing, net	46	20
Net cash (used in) provided by financing activities	(543)	210
Effect of exchange rate changes on cash	8	8
Net decrease in cash and cash equivalents	(438)	(41)
Cash and cash equivalents at beginning of period	684	493
Cash and cash equivalents at end of period	$246	$452

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 ("SEC") 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.

Beginning in the first quarter of 2013, we changed the presentation of our consolidated statements of income, primarily to present additional details of revenues and expenses and to classify certain expenses more consistently with our peer group of independent exploration and production companies. To effect these changes, reclassifications of previously reported amounts were made and are reflected in these consolidated financial statements. As a result of the reclassifications, general and administrative expenses for the second quarter and first six months of 2012 increased by $24 million and $63 million which primarily includes certain costs associated with operations support and operations management. Offsetting reductions are reflected in production, other operating and exploration expenses and taxes other than income.

These interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Marathon Oil Corporation 2012 Annual Report on Form 10-K. The results of operations for the second quarter and first six months of 2013 are not necessarily indicative of the results to be expected for the full year.

2. Accounting Standards

Not Yet Adopted

In June 2013, the Financial Accounting Standards Board ("FASB") ratified the Emerging Issues Task Force consensus on Issue 13-C, which requires that an unrecognized tax benefit or a portion of an unrecognized tax benefit be presented as a reduction to a deferred tax asset for an available net operating loss carryforward, a similar tax loss or tax credit carryforward. This accounting standards update is effective for us beginning in the first quarter of 2014 and should be applied prospectively to unrecognized tax benefits that exist as of the effective date. Early adoption and retrospective application are permitted. We do not expect this accounting standards update to have a significant impact on our consolidated results of operations, financial position or cash flows.

In February 2013, an accounting standards update was issued to provide guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date, except for obligations such as asset retirement and environmental obligations, contingencies, guarantees, income taxes and retirement benefits, which are separately addressed within United States generally accepted accounting principles ("U.S. GAAP"). An entity is required to measure obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date as the sum of 1) the amount the entity agreed to pay on the basis of its arrangement among its co-obligors and 2) any amount the entity expects to pay on behalf of its co-obligors. Disclosure of the nature of the obligation, including how the liability arose, the relationship with other co-obligors and the terms and conditions of the arrangement is required. In addition, the total outstanding amount under the arrangement, not reduced by the effect of any amounts that may be recoverable from other entities, plus the carrying amount of any liability or receivable recognized must be disclosed. This accounting standards update is effective for us beginning in the first quarter of 2014 and should be applied retrospectively for those in-scope obligations resulting from joint and several liability arrangements that exist at the beginning of 2014. Early adoption is permitted. We do not expect this accounting standards update to have a significant impact on our consolidated results of operations, financial position or cash flows.

Recently Adopted

In February 2013, an accounting standards update was issued to improve the reporting of reclassifications out of accumulated other comprehensive income. This standard requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under U.S. GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail about those amounts. This accounting standards update was effective for us beginning the first quarter of 2013 and we present the required disclosures in Note 15. Adoption of this standard did not have a significant impact on our consolidated results of operations, financial position or cash flows.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

In December 2011, an accounting standards update designed to enhance disclosures about offsetting assets and liabilities was issued. Further clarification limiting the scope of these disclosures to derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions was issued in January 2013. The disclosures are intended to enable financial statement users to evaluate the effect or potential effect of netting arrangements on an entity's financial position. Entities are required to disclose both gross information and net information about in-scope financial instruments that are either offset in the statement of financial position or subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset. The accounting standards update was effective for us beginning the first quarter of 2013 and we include the required disclosures in Note 13. Adoption of this standard did not have a significant impact on our consolidated results of operations, financial position or cash flows.

3. 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 current liabilities of $3 million recorded at June 30, 2013, consistent with December 31, 2012. 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 us. 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 $728 million as of June 30, 2013. 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.

4. Income per Common Share

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

	Three Months Ended June 30,			
	2013		2012	
(In millions, except per share data)	Basic	Diluted	Basic	Diluted
Net income	$426	$426	$393	$393
Weighted average common shares outstanding	710	710	706	706
Effect of dilutive securities	—	4	—	3
Weighted average common shares, including dilutive effect	710	714	706	709
Per share:				
Net income	$0.60	$0.60	$0.56	$0.56

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MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

	Six Months Ended June 30,			
	2013		2012	
(In millions, except per share data)	Basic	Diluted	Basic	Diluted
Net income	$809	$809	$810	$810
Weighted average common shares outstanding	709	709	705	705
Effect of dilutive securities	—	4	—	4
Weighted average common shares, including dilutive effect	709	713	705	709
Per share:				
Net income	$1.14	$1.14	$1.15	$1.14

The per share calculations above exclude 6 million stock options and stock appreciation rights for the second quarter and first six months of 2013. Excluded for the second quarter and first six months of 2012 were 10 million and 9 million stock options and stock appreciation rights.

5. Dispositions

2013 - North America Exploration and Production ("E&P") Segment

In June 2013, we closed the sale of our interests in the DJ Basin for proceeds of $19 million. A loss of $114 million was recorded in the second quarter of 2013.

In February 2013, we conveyed our interests in the Marcellus natural gas shale play to the operator. A $43 million loss on this transaction was recorded in the first quarter of 2013.

In February 2013, we closed the sale of our interest in the Neptune gas plant, located onshore Louisiana, for proceeds of $166 million. A $98 million gain was recorded in the first quarter of 2013.

In January 2013, we closed the sale of our remaining assets in Alaska, for proceeds of $195 million, subject to a six-month escrow of $50 million which was collected in July 2013. After closing adjustments made in the second quarter of 2013, the gain on this sale was $55 million.

2013 - International E&P Segment

In June 2013, we entered into an agreement to sell our non-operated 10 percent working interest in the Production Sharing Contract and Joint Operating Agreement in Block 31 offshore Angola. This transaction, valued at $1.5 billion before closing adjustments, is expected to close in the fourth quarter of 2013, subject to government, regulatory and third-party approvals. Angola Block 31 is reflected as held for sale in the June 30, 2013 consolidated balance sheet as follows:

(In millions)	
Other noncurrent assets	$1,550
Total assets	1,550
Other current liabilities	58
Deferred credits and other liabilities	39
Total liabilities	$97

2012 - North America E&P Segment

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 included 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 gain of $166 million was recorded in the first quarter of 2012.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

2012 - International E&P Segment
In May 2012, we reached an agreement to relinquish our operatorship of and interests in the Bone Bay and Kumawa exploration licenses in Indonesia. A $36 million payment to settle all of our obligations related to these licenses, including well commitments, was accrued and reported as a loss on disposal of assets in the second quarter of 2012.

6. Segment Information

Beginning in 2013, we changed our reportable segments and revised our management reporting to better reflect the growing importance of United States unconventional resource plays to our business. All periods presented have been recast to reflect these new segments.

We have three reportable operating segments. Each of these segments is organized and managed based upon both geographic location and the nature of the products and services it offers.

- North America E&P ("N.A. E&P") – explores for, produces and markets liquid hydrocarbons and natural gas in North America;
- International E&P ("Int'l E&P") – explores for, produces and markets liquid hydrocarbons and natural gas outside of North America and produces and markets products manufactured from natural gas, such as liquefied natural gas ("LNG")and methanol, in Equatorial Guinea; and
- 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.

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 excluding certain items not allocated to segments as discussed below, net of income taxes, attributable to the operating segments. Our corporate and operations support general and administrative costs are not allocated to the operating segments. These costs primarily consist of employment costs (including pension effects), professional services, facilities and other costs associated with corporate and operations support activities, net of associated income tax effects. Unrealized gains or losses on crude oil derivative instruments, 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.

	Three Months Ended June 30, 2013			
(In millions)	N.A. E&P	Int'l E&P	OSM	Total
Revenues:				
Sales and other operating revenues	$ 1,284	$ 1,732	$ 353	$ 3,369
Marketing revenues	439	51	9	499
Segment revenues	$ 1,723	$ 1,783	$ 362	3,868
Unrealized gain on crude oil derivative instruments				50
Total revenues				$ 3,918
Segment income	$ 221	$ 382	$ 20	$ 623
Income from equity method investments	—	77	—	77
Depreciation, depletion and amortization	490	189	48	727
Income tax provision	129	1,004	7	1,140
Capital expenditures	904	241	97	1,242

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

	Three Months Ended June 30, 2012			
(In millions)	N.A. E&P	Int'l E&P	OSM	Total
Revenues:				
Sales and other operating revenues	$833	$1,813	$329	$2,975
Marketing revenues	696	56	5	757
Total revenues	$1,529	$1,869	$334	$3,732
Segment income	$70	$373	$50	$493
Income from equity method investments	—	60	—	60
Depreciation, depletion and amortization	290	228	50	568
Income tax provision	39	1,070	17	1,126
Capital expenditures	1,013	202	43	1,258

	Six Months Ended June 30, 2013			
(In millions)	N.A. E&P	Int'l E&P	OSM	Total
Revenues:				
Sales and other operating revenues	$2,499	$3,619	$741	$6,859
Marketing revenues	784	136	9	929
Segment revenues	$3,283	$3,755	$750	7,788
Unrealized loss on crude oil derivative instruments				—
Total revenues				$7,788
Segment income	$162	$835	$58	$1,055
Income from equity method investments	—	195	—	195
Depreciation, depletion and amortization	968	396	100	1,464
Income tax provision	99	2,146	20	2,265
Capital expenditures	1,874	466	142	2,482

	Six Months Ended June 30, 2012			
(In millions)	N.A. E&P	Int'l E&P	OSM	Total
Revenues:				
Sales and other operating revenues	$1,745	$3,476	$698	$5,919
Marketing revenues	1,471	120	15	1,606
Total revenues	$3,216	$3,596	$713	$7,525
Segment income	$174	$780	$88	$1,042
Income from equity method investments	1	137	—	138
Depreciation, depletion and amortization	604	428	99	1,131
Income tax provision	100	2,041	30	2,171
Capital expenditures	1,842	340	95	2,277

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2013	2012	2013	2012
Total revenues	$3,918	$3,732	$7,788	$7,525
Less: Marketing revenues	499	757	929	1,606
Sales and other operating revenues, including related party	$3,419	$2,975	$6,859	$5,919

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 June 30,		Six Months Ended June 30,	
(In millions)	2013	2012	2013	2012
Segment income	$623	$493	$1,055	$1,042
Items not allocated to segments, net of income taxes:				
Corporate and other unallocated items	(156)	(77)	(227)	(148)
Unrealized gain (loss) on crude oil derivative instruments	32	—	—	—
Net gain (loss) on dispositions	(73)	(23)	(9)	83
Impairments	—	—	(10)	(167)
Net income	$426	$393	$809	$810

7. Defined Benefit Postretirement Plans

The following summarizes the components of net periodic benefit cost:

	Three Months Ended June 30,			
	Pension Benefits		Other Benefits	
(In millions)	2013	2012	2013	2012
Service cost	$14	$13	$1	$1
Interest cost	16	16	3	3
Expected return on plan assets	(16)	(16)	—	—
Amortization:				
– prior service cost (credit)	1	2	(1)	(1)
– actuarial loss	16	13	—	—
Net settlement loss[a]	17	—	—	—
Net periodic benefit cost	$48	$28	$3	$3

	Six Months Ended June 30,			
	Pension Benefits		Other Benefits	
(In millions)	2013	2012	2013	2012
Service cost	$28	$25	$2	$2
Interest cost	31	32	6	7
Expected return on plan assets	(33)	(32)	—	—
Amortization:				
– prior service cost (credit)	3	4	(3)	(3)
– actuarial loss	29	25	—	—
Net settlement loss[a]	17	—	—	—
Net periodic benefit cost	$75	$54	$5	$6

(a) Settlements are recognized as they occur, once it is probable that lump sum payments from a plan for a given year will exceed the plan's total service and interest cost for that year. Such settlements were recorded for our U.S. plans in the second quarter of 2013.

During the second quarter of 2013, we recorded the effects of partial settlements of our U.S. pension plans and we remeasured the plans' assets and liabilities as of June 30, 2013, using a discount rate of 4.14 percent as of that date. As a result, we recognized a decrease of $139 million in actuarial losses, in other comprehensive income.

During the first six months of 2013, we made contributions of $28 million to our funded pension plans. We expect to make additional contributions up to an estimated $39 million to our funded pension plans over the remainder of 2013. Current benefit payments related to unfunded pension and other postretirement benefit plans were $10 million and $7 million during the first six months of 2013.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

8. Income Taxes

The effective income tax rate is influenced by a variety of factors including the geographic 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 6.

Our effective income tax rates in the first six months of 2013 and 2012 were 72 percent and 71 percent. These rates are higher than the U.S. statutory rate of 35 percent due to earnings from foreign jurisdictions, primarily Norway and Libya, where the tax rates are in excess of the U.S. statutory rate. In Libya, where the statutory tax rate is in excess of 90 percent, there remains uncertainty around sustained production and sales levels. Reliable estimates of 2013 and 2012 annual ordinary income from our Libyan operations could not 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 six months of 2013 and 2012, estimated annual effective tax rates were 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 periods. Excluding Libya, the effective tax rates would be 63 percent and 64 percent for the first six months of 2013 and 2012.

9. Inventories

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

(In millions)	June 30, 2013	December 31, 2012
Liquid hydrocarbons, natural gas and bitumen	$48	$73
Supplies and other items	320	288
Inventories, at cost	$368	$361

10. Property, Plant and Equipment

(In millions)	June 30, 2013	December 31, 2012
North America E&P	$25,129	$23,748
International E&P	12,213	13,214
Oil Sands Mining	10,270	10,127
Corporate	484	449
Total property, plant and equipment	48,096	47,538
Less accumulated depreciation, depletion and amortization	(20,639)	(19,266)
Net property, plant and equipment	$27,457	$28,272

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 sales volumes have increased to near pre-conflict levels. 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. As of June 30, 2013, our net property, plant and equipment investment in Libya was approximately $740 million.

Exploratory well costs capitalized greater than one year after completion of drilling were $220 million as of June 30, 2013. The net decrease from December 31, 2012 primarily related to the conveyance of our interests in the Marcellus natural gas shale play to the operator in February 2013.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

11. Asset Retirement Obligations

The following summarizes the changes in asset retirement obligations during the first six months of 2013:

(In millions)	
Beginning balance	$1,783
Incurred, including acquisitions	8
Settled, including dispositions	(27)
Accretion expense (included in depreciation, depletion and amortization)	48
Revisions to previous estimates	306
Held for sale	(39)
Ending balance[(a)]	$2,079

[(a)] Includes asset retirement obligations of $40 million classified as a short-term at June 30, 2013.

12. Fair Value Measurements

Fair Values - Recurring

The following tables present assets and liabilities accounted for at fair value on a recurring basis as of June 30, 2013 and December 31, 2012 by fair value hierarchy level.

	June 30, 2013				
(In millions)	Level 1	Level 2	Level 3	Collateral	Total
Derivative instruments, assets					
Commodity	$—	$52	$—	$—	$52
Interest rate	—	6	—	—	6
Derivative instruments, assets	$—	$58	$—	$—	$58
Derivative instruments, liabilities					
Foreign currency	$—	$30	$—	$—	$30
Derivative instruments, liabilities	$—	$30	$—	$—	$30

	December 31, 2012				
(In millions)	Level 1	Level 2	Level 3	Collateral	Total
Derivative instruments, assets					
Commodity	$—	$52	$—	$1	$53
Interest rate	—	21	—	—	21
Foreign currency	—	18	—	—	18
Derivative instruments, assets	$—	$91	$—	$1	$92

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 or 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 to this fair value measurement 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 or liabilities, and are Level 2 inputs.

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Notes to Consolidated Financial Statements (Unaudited)

Fair Values - Nonrecurring
The following table shows the values of assets, by major category, measured at fair value on a nonrecurring basis in periods subsequent to their initial recognition.

	Three Months Ended June 30,			
	2013		2012	
(In millions)	Fair Value	Impairment	Fair Value	Impairment
Long-lived assets held for use	$—	$—	$—	$1

	Six Months Ended June 30,			
	2013		2012	
(In millions)	Fair Value	Impairment	Fair Value	Impairment
Long-lived assets held for use	$—	$38	$75	$263

All long-lived assets held for use that were impaired in the first six months of 2013 and 2012 were held by our North America E&P segment. The fair values of each discussed below were measured using an income approach based upon internal estimates of future production levels, prices and discount rate, all of which are Level 3 inputs. Inputs to the fair value measurement included reserve and production estimates made by our reservoir engineers, estimated commodity prices adjusted for quality and location differentials, and forecasted operating expenses for the remaining estimated life of the reservoir.
In the first quarter of 2013, as a result of our decision to wind down operations in the Powder River Basin due to poor economics, an impairment of $15 million was recorded.
In early 2012, production rates from the Ozona development in the Gulf of Mexico declined significantly. Accordingly, our reserve engineers prepared evaluations of our future production as well as our reserves and an impairment of $261 million was recorded in the first quarter of 2012. As the development produced towards abandonment pressures, further downward revisions of reserves were taken, resulting in an additional impairment recorded in the fourth quarter of 2012. Ozona production ceased in the first quarter of 2013 and an additional $21 million impairment was recorded.
Other impairments of long-lived assets held for use by our North America E&P segment in the first six months of 2013 and 2012 were a result of reduced drilling expectations, reductions of estimated reserves or declining natural gas prices.
Fair Values – Financial Instruments
Our current assets and liabilities include financial instruments, the most significant of which are receivables, commercial paper and payables. We believe the carrying values of our receivables, commercial paper 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 receivables, commercial paper, payables and derivative financial instruments, and their reported fair value by individual balance sheet line item at June 30, 2013 and December 31, 2012.

	June 30, 2013		December 31, 2012	
	Fair	Carrying	Fair	Carrying
(In millions)	Value	Amount	Value	Amount
Financial assets				
Other noncurrent assets	$165	$164	$189	$186
Total financial assets	165	164	189	186
Financial liabilities				
Other current liabilities	13	13	13	13

Long-term debt, including current portion[a]	6,991	6,460	7,610	6,642
Deferred credits and other liabilities	141	140	94	94
Total financial liabilities	$7,145	$6,613	$7,717	$6,749

[a] Excludes capital leases.

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Notes to Consolidated Financial Statements (Unaudited)

Fair values of our financial assets included in 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 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.

13. Derivatives

For information regarding the fair value measurement of derivative instruments, see Note 12. All of our interest rate and commodity derivatives are subject to enforceable master netting arrangements or similar agreements under which we may report net amounts. Netting is assessed by counterparty, and as of June 30, 2013 and December 31, 2012, there were no offsetting amounts. Positions by contract were all either assets or liabilities. The following tables present the gross fair values of derivative instruments, excluding cash collateral, and the reported net amounts along with where they appear on the consolidated balance sheets as of June 30, 2013 and December 31, 2012.

	June 30, 2013			
(In millions)	Asset	Liability	Net Asset	Balance Sheet Location
Fair Value Hedges				
Interest rate	$6	$—	$6	Other noncurrent assets
Total Designated Hedges	6	—	6	
Not Designated as Hedges				
Commodity	52	—	52	Other current assets
Total Not Designated as Hedges	52	—	52	
Total	$58	$—	$58	

	June 30, 2013			
(In millions)	Asset	Liability	Net Liability	Balance Sheet Location
Fair Value Hedges				
Foreign currency	$—	$30	$30	Other current liabilities
Total Designated Hedges	—	30	30	
Total	$—	$30	$30	

	December 31, 2012			
(In millions)	Asset	Liability	Net Asset	Balance Sheet Location
Fair Value Hedges				
Foreign currency	$18	$—	$18	Other current assets
Interest rate	21	—	21	Other noncurrent assets
Total Designated Hedges	39	—	39	
Not Designated as Hedges				
Commodity	52	—	52	Other current assets
Total Not Designated as Hedges	52	—	52	
Total	$91	$—	$91	

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

Derivatives Designated as Fair Value Hedges

As of June 30, 2013 and December 31, 2012, we had multiple interest rate swap agreements with a total notional amount of $600 million with a maturity date of October 1, 2017 at a weighted average, London Interbank Offer Rate ("LIBOR")-based, floating rate of 4.68 percent and 4.70 percent.

As of June 30, 2013 and December 31, 2012, our foreign currency forwards had an aggregate notional amount of 2,965 million and 3,043 million Norwegian Kroner at a weighted average forward rate of 5.738 and 5.780. These forwards hedge our current Norwegian tax liability and have settlement dates through December 2013.

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 June 30,		Six Months Ended June 30,	
(In millions)	Income Statement Location	2013	2012	2013	2012
Derivative					
Interest rate	Net interest and other	$(12)	$12	$(15)	$12
Foreign currency	Provision for income taxes	$(21)	$(32)	$(46)	$(40)
Hedged Item					
Long-term debt	Net interest and other	$12	$(12)	$15	$(12)
Accrued taxes	Provision for income taxes	$21	$32	$46	$40

Derivatives not Designated as Hedges

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

Remaining Term	Bbls per Day	Weighted Average Price per Bbl	Benchmark
Swaps			
July 2013 - December 2013	20,000	$96.29	West Texas Intermediate
July 2013 - December 2013	25,000	$109.19	Brent
Option Collars			
July 2013 - December 2013	15,000	$90.00 floor / $101.17 ceiling	West Texas Intermediate
July 2013 - 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 June 30,		Six Months Ended June 30,	
(In millions)	Income Statement Location	2013	2012	2013	2012
Commodity	Sales and other operating revenues, including related party	$67	$(1)	$13	$2

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

14. Incentive Based Compensation

Stock option and restricted stock awards

The following table presents a summary of stock option and restricted stock award activity for the first six months of 2013:

	Stock Options		Restricted Stock	
	Number of Shares	Weighted Average Exercise Price	Awards	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2012	19,536,965	$26.19	4,177,884	$29.02
Granted	1,381,321 [(a)]	$32.85	1,087,731	$32.38
Options Exercised/Stock Vested	(1,422,488)	$21.53	(605,209)	$29.73
Cancelled	(386,186)	$34.54	(182,958)	$29.35
Outstanding at June 30, 2013	19,109,612	$26.85	4,477,448	$29.79

[(a)] The weighted average grant date fair value of stock option awards granted was $10.25 per share.

Performance unit awards

In the first quarter of 2013, we granted 353,600 performance units to certain officers that provide a cash payout upon the achievement of certain performance goals at the end of a 36-month performance period. The performance goals are tied to our total shareholder return ("TSR") as compared to TSR for a group of peer companies determined by the Compensation Committee of the Board of Directors. At the grant date, each unit represents the value of one share of our common stock, while payout after completion of the performance period will be based on the value of anywhere from zero to two times the number of units granted. Dividend equivalents accrue during the performance period and are paid in cash at the end of the performance period based on the number of shares that would represent the value of the units. The fair value of these performance units is re-measured on a quarterly basis using the Monte Carlo simulation method. These performance units are accounted for as liability awards because they are to be settled in cash at the end of the performance period and their fair value is expensed over the performance period.

15. Reclassifications Out of Accumulated Other Comprehensive Loss

The following table presents a summary of amounts reclassified from accumulated other comprehensive loss to net income in their entirety:

(In millions)	Three Months Ended June 30, 2013	Six Months Ended June 30, 2013	Income Statement Line
Accumulated Other Comprehensive Loss Components			
	Income (Expense)		
Amortization of postretirement and postemployment plans			
Actuarial loss	$(16)	$(29)	General and administrative
Net settlement loss	(17)	(17)	General and administrative
	12	17	Provision for income taxes
Total reclassifications for the period	$(21)	$(29)	Net income

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Notes to Consolidated Financial Statements (Unaudited)

16. Supplemental Cash Flow Information

	Six Months Ended June 30,	
(In millions)	2013	2012
Net cash provided from operating activities:		
Interest paid (net of amounts capitalized)	$160	$113
Income taxes paid to taxing authorities	2,474	2,317
Commercial paper, net:		
Commercial paper - issuances	$2,075	$4,252
- repayments	(2,275)	(3,702)
Noncash investing activities:		
Asset retirement costs capitalized	$314	$34
Debt payments made by United States Steel	—	14
Change in capital expenditure accrual	(149)	159
Asset retirement obligations assumed by buyer	92	7
Receivable for disposal of assets	50	—

17. Commitments and Contingencies

We are a 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. In April 2013, we filed a counterclaim against Noble alleging, among other things, breach of contract and breach of the duty of good faith relating to the multi-year drilling contract. The counterclaim also included a breach of contract claim for reimbursement for the value of fuel used by Noble under an offshore daywork drilling contract. 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.

Contractual commitments – At June 30, 2013, Marathon’s contract commitments to acquire property, plant and equipment were $1,122 million.

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

Beginning in 2013, we changed our reportable segments and revised our management reporting to better reflect the growing importance of United States unconventional resource plays to our business. All periods presented have been recast to reflect these new segments.

We are an international energy company with operations in the United States, Canada, Africa, the Middle East and Europe. We have three reportable operating segments. Each of these segments is organized and managed based upon both geographic location and the nature of the products and services it offers.

- North America Exploration and Production ("E&P") – explores for, produces and markets liquid hydrocarbons and natural gas in North America;
- International E&P – explores for, produces and markets liquid hydrocarbons and natural gas outside of North America and produces and markets products manufactured from natural gas, such as LNG and methanol, in Equatorial Guinea; and
- Oil Sands Mining – 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.

Certain sections of this Quarterly Report on Form 10-Q, including Management's Discussion and Analysis of Financial Condition and Results of Operations contain 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," "would" or similar words indicating that future outcomes a 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 2012 Annual Report on Form 10-K. We assume no duty to update these statements as to any future date.

Key Operating and Financial Activities

In the second quarter of 2013, notable items were:

- Total net sales volumes averaged 506 thousand barrels of oil equivalent per day ("mboed"), a 12 percent increase over the same quarter of last year
- North America E&P net sales volumes increased 38 percent over the same quarter of last year
- Eagle Ford shale averaged net sales volumes of 80 mboed, a 286 percent increase
- Bakken shale averaged net sales volumes of 39 mboed, a 49 percent increase
- Turnaround in Equatorial Guinea started and safely completed in April, eight days ahead of schedule and below budget
- Successful appraisal well on non-operated Gunflint prospect in the Gulf of Mexico announced by operator
- Two Gulf of Mexico leases from Lease Sale 227 awarded to us
- Entered into agreement to sell our working interest in Angola Block 31 in a transaction valued at $1.5 billion before closing adjustments
- Concluded exploration activities in Poland
- Closed sale of interests in DJ Basin and recorded a $114 million loss on sale

Some significant third quarter activities to August 8, 2013 include:

- Increased dividend 12 percent to 19 cents per share

Overview and Outlook

North America E&P

Production

Net liquid hydrocarbon and natural gas sales volumes averaged 201 mboed and 200 mboed during the second quarter and first six months of 2013 compared to 146 mboed in both periods of 2012, for increases of approximately 37 percent in both periods. Net liquid hydrocarbon sales volumes increased for both the quarter and the first six months of 2013, primarily reflecting the impact of our ongoing development programs in the Eagle Ford and Bakken shale resource plays, while net natural gas sales volumes decreased slightly during the same periods due to the sale of our Alaska assets in January 2013. Excluding the sales volume related to Alaska in both six-month periods, our average net liquid hydrocarbon and natural gas sales volumes increased 50 percent.

Eagle Ford – In 2013, production growth continued in the Eagle Ford shale play. Average net sales volumes were 80 mboed and 76 mboed in the second quarter and first six months of 2013 compared to 21 mboed and 18 mboed in the same periods of 2012. Approximately 63 percent of the first six months of 2013 production was crude oil and condensate, 17 percent was natural gas liquids ("NGLs") and 20 percent was natural gas. In the second quarter of 2013, we increased the amount of crude oil and condensate transported by pipeline to 70 percent from 65 percent in the previous quarter. The ability to transport more barrels by pipeline enables us to reduce costs, improve reliability and lessen our environmental footprint.

During the second quarter of 2013, we reached total depth on 82 gross operated wells and brought 70 gross operated wells to sales, with 158 gross operated wells reaching total depth and 138 gross operated wells brought on line in the first six months of 2013. With approximately 85 percent pad drilling, which continues to improve efficiencies and reduce costs, our second quarter average spud-to-total depth time was 12 days and spud-to-spud was 18 days.

To support production growth across the Eagle Ford operating area, approximately 170 miles of gathering lines were installed in the first six months of 2013, bringing the total to more than 650 miles. We also commissioned six new central gathering and treating facilities and have three additional facilities in various stages of planning or construction, bringing the total to 27.

We continue to evaluate the potential of downspacing to 40-acre and 60-acre units, with the results of the downspacing pilots expected to be released in December 2013. We also continue to evaluate the Austin Chalk and Pearsall formations across our acreage position. To date, we have completed four Austin Chalk wells with average 24-hour initial production ("IP") rates of 980 gross barrels of oil equivalent per day (“boed”) (485 barrels per day ("bbld") of crude oil and condensate, 220 bbld of NGLs and 1.65 million cubic feet per day ("mmcfd") of natural gas). Early Austin Chalk production results suggest that the mix of crude oil and condensate, NGLs and natural gas is similar to Eagle Ford condensate wells. Also in the second quarter of 2013, one Pearsall well was completed with a 24-hour IP rate of 580 gross boed.

Bakken – Average net sales volumes from the Bakken shale were 39 mboed and 38 mboed in the second quarter and first six months of 2013 compared to 26 mboed in the same periods of 2012. Our Bakken production averages approximately 90 percent crude oil, 5 percent NGLs and 5 percent natural gas. During the second quarter of 2013, we reached total depth on 22 gross operated wells and brought 16 gross operated wells to sales. During the first six months of 2013 we reached total depth on 40 gross operated wells and brought 38 gross operated wells to sales. Our second quarter average time to drill a well continued to improve, averaging 15 days spud-to-total depth and 22 days spud-to-spud.

Oklahoma Resource Basins – Net sales volumes from the Anadarko Woodford shale averaged 13 mboed in the second quarter and first six months of 2013 compared to 6 mboed and 5 mboed in the same periods of 2012. During the second quarter of 2013, we reached total depth on two gross operated wells and three gross operated wells were brought to sales, while during the first six months of 2013 we reached total depth on two gross operated wells and brought seven gross operated wells to sales. We anticipate drilling will begin on two wells each in the Mississippi Lime formation in central Oklahoma and the Granite Wash formation in northwestern Oklahoma during the second half of 2013.

Exploration

Gulf of Mexico – Late in the third quarter of 2013, we expect to begin drilling the first exploration well on the Madagascar prospect located on De Soto Canyon Block 757. We reduced our working interest in the Madagascar prospect from 100 percent to 70 percent as a result of a farm-down in the second quarter of 2013 with no up-front cash proceeds. We anticipate further reducing our interest to a target of 40 to 50 percent working interest by the time of drilling.

We participated in an appraisal well on the Gunflint prospect located on Mississippi Canyon Block 992 in which we hold an 18 percent non-operated working interest. The appraisal well successfully encountered 109 feet of net pay within the primary reservoir targets. After penetrating the initial appraisal targets, the well was deepened to a previously untested Lower Miocene interval. Commercial hydrocarbons were not encountered in the deeper exploration objective. Additional exploration potential remains in an adjacent structure to the north, which is a candidate for future exploration following development of the confirmed resources.

The first appraisal well on the Shenandoah prospect located on Walker Ridge Block 51, in which we have a 10 percent non-operated working interest, reached total depth in the first quarter of 2013. This appraisal well successfully encountered more than 1,000 net feet of oil pay in multiple high-quality Lower Tertiary-aged reservoirs.

In March 2013, we submitted bids totaling $33 million for 100 percent working interest in two blocks in the Central Gulf of Mexico Lease Sale 227: Keathley Canyon Block 340 on the Colonial prospect and Keathley Canyon Block 153, an extension to the Meteor prospect on our existing Keathley Canyon 196 lease. Keathley Canyon Blocks 340 and 153 are both inboard-Paleogene prospects. These leases were awarded to us in the second quarter of 2013.

Canada – During the first quarter of 2012, we submitted a regulatory application relating to our Canada in-situ assets at Birchwood, for a proposed 12 thousand barrels per day ("mbbld") steam assisted gravity drainage ("SAGD") demonstration project. We are expecting to receive regulatory approval for this project in early 2014. Upon receiving this approval, we will further evaluate our development plans.

International E&P

Production

Net liquid hydrocarbon and natural gas sales volumes averaged 262 mboed and 268 mboed during the second quarter and first six months of 2013 compared to 261 mboed and 249 mboed in the same periods of 2012, which is flat for the quarter and an increase of 8 percent for the six-month period. During the first six months of 2013, Libya net liquid hydrocarbon and natural gas sales volumes increased 5 mboed and 13 mboed, compared to the same periods of 2012, primarily due to limited resumption of sales in early 2012 after the 2011 civil unrest. In addition, both the second quarter and first six months of 2013 include net liquid hydrocarbon sales volumes of 9 mboed from the PSVM development located on the northeastern portion of Angola Block 31 which had first sales in February 2013.

Equatorial Guinea – Average net sales volumes were 97 mboed and 105 mboed in the second quarter and first six months compared to 101 mboed and 103 mboed in the same periods of 2012. The planned turnaround that occurred in April 2013 was safely completed in 22 days, eight days ahead of schedule and below budget. Sales in the second quarter of 2013 were impacted by the turnaround, but operational availability of 98 percent in the first quarter of 2013 bolstered sales for the six-month period.

Norway – The production decline in the Alvheim area continues to be less than expected. Average net sales volumes from Norway were 88 mboed in both the second quarter and first six months of 2013 compared to 86 mboed and 92 mboed in the same periods of 2012. These better-than-expected results have been achieved through continued strong operational performance that delivered availability of approximately 96 percent in the second quarter and 97 percent in the first quarter of 2013; production optimization from well management; and reservoir and well performance at the upper end of expectations primarily due to a delay in anticipated water breakthrough at the Volund field. A planned 10-day turnaround in Norway is scheduled during the third quarter of 2013.

United Kingdom – Production at non-operated Foinaven was shut-in in mid-July 2013 due to compression and subsea equipment issues and is expected to resume at partial rates in mid-August. Planned pipeline curtailments and a turnaround at Brae in the North Sea in the second half of 2013 will also reduce third quarter 2013 production.

Exploration

Kurdistan Region of Iraq – We hold 45 percent operated working interests in both the Harir and Safen blocks. Current exploratory drilling includes the Mirawa well which began in March 2013 on the Harir Block and the Safen well which commenced drilling in April 2013 on the Safen Block. The Mirawa well reached total depth in July 2013 and is currently testing. The Safen well is expected to reach projected total depth in August 2013, with testing programs to follow.

Additionally, following the successful appraisal program on the non-operated Atrush Block a declaration of commerciality was filed with the government in 2012, and a plan of development was filed in May 2013. The development plan is currently under review with final approval expected in the third quarter of 2013. We anticipate first production in 2015. The Atrush-3 appraisal well has reached total depth and is currently testing. We hold a 15 percent non-operated working interest in the Atrush Block.

On the non-operated Sarsang block, two exploration wells, the Mangesh and the Gara, began drilling in the second half of 2012 and have reached total depth, with testing programs ongoing. Also on the Sarsang block, the East Swara

Tika exploration well began drilling in July 2013 to test additional resource potential to the northeast of the previously announced Swara Tika discovery. We hold a 25 percent working interest in the Sarsang Block.

Ethiopia – The Sabisa-1 exploration well, on the onshore South Omo block in a frontier rift basin, encountered reservoir quality sands, oil and heavy gas shows and a thick shale section. The presence of oil prone source rocks, reservoir sands and good seals is encouraging for the numerous fault bounded traps identified in the basin. Because of mechanical issues, the well was abandoned before a full evaluation could be completed. The rig will mobilize to the nearby Tultule prospect, approximately two miles from the Sabisa-1 during the second half of 2013. We hold a 20 percent non-operated working interest in the South Omo block.

Gabon – Exploration drilling began in April 2013 on the Diaman well in the Diaba License G4-223, offshore Gabon, to test the deepwater presalt play. The well reached total depth in the third quarter of 2013. Logging and evaluation are underway. We hold a 21 percent non-operated working interest in the Diaba License.

Norway – We commenced drilling of the Sverdrup exploration well on PL 330 offshore Norway in June 2013 and total depth is expected to be reached in early September 2013. We hold a 30 percent non-operated working interest in this license. The Darwin (formerly Veslemoy) exploration well was drilled in the first quarter of 2013 on PL 531 in which we hold a 10 percent non-operated fully-carried working interest. Gas shows were recorded in the Paleocene objective section, although no hydrocarbons were found in the Cretaceous section and the well has been plugged and abandoned.

Poland – After an extensive evaluation of our exploration activities in Poland and unsuccessful attempts to find commercial levels of hydrocarbons, we have elected to conclude operations in the country. We are evaluating disposition options for our concessions.

Kenya – The first exploratory well on Block 9 is expected to commence before the end of 2013 onshore Kenya where we hold a 50 percent non-operated working interest.

Angola – The Kaombo development, located in the southeastern portion of Block 32, is expected be sanctioned late in 2013 so that production from the Kaombo development is possible in 2017.

Oil Sands Mining

Our Oil Sands Mining operations consist of a 20 percent non-operated working interest in the Athabasca Oil Sands Project ("AOSP"). Our net synthetic crude oil sales were 43 mbbld and 47 mbbld in the second quarter and first six months of 2013 compared to 44 mbbld in each of the same periods of 2012. Sales were relatively flat in all periods with the exception of the first six months of 2013. The impact of strong reliability experienced at both mines and the upgrader during the first quarter of 2013 was partially offset by unplanned mine downtime and a planned turnaround during the second quarter of 2013.

Acquisitions and Dispositions

In June 2013, we entered into an agreement to sell our non-operated 10 percent working interest in the Production Sharing Contract and Joint Operating Agreement in Block 31 offshore Angola. This transaction, valued at $1.5 billion before closing adjustments, is expected to close in the fourth quarter of 2013, subject to government, regulatory and third-party approvals.

In June 2013, we closed the sale of our interests in the DJ Basin for proceeds of $19 million. A pretax loss of $114 million was recorded in the second quarter of 2013.

In February 2013, we conveyed our interests in the Marcellus natural gas shale play to the operator. A $43 million pretax loss on this transaction was recorded in the first quarter of 2013.

In February 2013, we closed the sale of our interest in the Neptune gas plant, located onshore Louisiana, for proceeds of $166 million. A $98 million pretax gain was recorded in the first quarter of 2013.

In January 2013, we closed the sale of our remaining assets in Alaska, for proceeds of $195 million, subject to a six-month escrow of $50 million which was collected in July 2013. After closing adjustments made in the second quarter of 2013, the pretax gain on this sale was $55 million.

In January 2013, government approval was received for our acquisition of a 20 percent non-operated interest in the onshore South Omo concession in Ethiopia.

As previously disclosed, we had engaged in discussions with respect to a potential sale of a portion of our 20 percent outside-operated interest in the AOSP. An agreement was not reached with the prospective purchaser and negotiations have been terminated. We are not engaged in further discussions with respect to a potential sale of these assets.

We continue to progress the potential sale of assets in an ongoing effort to optimize our portfolio for profitable growth, 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 agreed upon or completed divestitures of approximately $2.9 billion.
The above discussions include forward-looking statements with respect to anticipated drilling activity, possible increased recoverable resources from optimized well spacing in the Eagle Ford resource play, planned infrastructure improvements in the

Eagle Ford operating area, additional farm-down of our working interest in the Madagascar prospect in the Gulf of Mexico, anticipated exploration activity in the Gulf of Mexico, the Kurdistan Region of Iraq, Ethiopia, Gabon, Norway, and Kenya, the development of our in-situ assets, a planned turnaround in Norway, planned pipeline curtailments and turnaround at Brae in the North Sea, expected timing and rate of production returning at Foinaven, the timing of approval of a plan of development and first production for the Atrush Block, plans to exit Poland, the timing of closing the sale of our 10 percent working interest in Block 31 offshore Angola, and the projected asset dispositions through 2013. The average times to drill a well and expectations as to future drilling times may not be indicative of future drilling times. The current production rates may not be indicative of future production rates. Factors that could potentially affect anticipated drilling activity, possible increased recoverable resources from optimized well spacing in the Eagle Ford resource play, planned infrastructure improvements in the Eagle Ford operating area, anticipated exploratory activity in the Gulf of Mexico, the Kurdistan Region of Iraq, Ethiopia, Gabon, Norway, and Kenya, a planned turnaround in Norway and planned pipeline curtailments and turnaround at Brae in the North Sea 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, availability of materials and labor, other associated risks with construction projects, the inability to obtain or delay in obtaining necessary government and third-party approvals and permits, 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 timing of closing the sale of our 10 percent working interest in Block 31 offshore Angola is subject to the satisfaction of customary closing conditions and obtaining necessary government, regulatory and third-party approvals. The expected timing and rate of production returning at Foinaven, additional farm-down of the our working interest in the Madagascar prospect in the Gulf of Mexico, plans to exit Poland, the timing of approval of a plan of development and first production for the Atrush Block and the projected asset dispositions through 2013 are based on current expectations, estimates, and projections and are not guarantees of future performance. The development of our in-situ assets is dependent on obtaining regulatory approval and future development plans. 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.

Market Conditions

Prevailing prices for the various qualities of crude oil and natural gas that we produce significantly impact our revenues and cash flows. Worldwide prices have been volatile in recent years. The following table lists benchmark crude oil and natural gas price averages relative to our North America E&P and International E&P segments in the second quarter and first six months of 2013 and 2012.

	Three Months Ended June 30,		Six Months Ended June 30,	
Benchmark	2013	2012	2013	2012
West Texas Intermediate ("WTI") crude oil (Dollars per barrel)	$94.17	$93.35	$94.26	$98.15
Brent (Europe) crude oil (Dollars per barrel)	$102.58	$108.42	$107.54	$113.45
Henry Hub natural gas (Dollars per million British thermal units ("mmbtu"))[a]	$4.09	$2.22	$3.71	$2.48

[a] Settlement date average.

North America E&P

Liquid hydrocarbons – The quality, location and composition of our liquid hydrocarbon production mix can cause our U.S. liquid hydrocarbon realizations to differ from the WTI benchmark.

Quality – Light sweet crude contains less sulfur and tends to be lighter than sour crude oil so that refining it is less costly and produces higher value products; therefore, light sweet crude is considered of higher quality and typically sells at a price that approximates WTI or at a premium to WTI. The percentage of our North America E&P crude and condensate production that is light sweet crude has been increasing as onshore production from the Eagle Ford and Bakken shale plays increases and production from the Gulf of Mexico declines. In the second quarter and first six months of 2013, the percentage of our U.S. crude oil and condensate production that was sweet averaged 75 percent and 74 percent compared to 42 percent and 45 percent in the same periods of 2012.

Location – In recent years, crude oil sold along the United States Gulf Coast, such as that from the Eagle Ford shale, has been priced based on the Louisiana Light Sweet benchmark which prices at a premium to WTI and tracks closest to Brent, while production from inland areas farther from large refineries has been at a discount to WTI.

Composition – The proportion of our liquid hydrocarbon sales that are NGLs continues to increase due to our development of United States unconventional liquids-rich plays. NGLs were 14 percent of our North America E&P liquid hydrocarbon sales volumes in the second quarter and first six months of 2013 compared to 9 percent in the same periods of 2012.

Natural gas – A significant portion of our natural gas production in 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 84 percent and 50 percent higher for the second quarter and first six months of 2013 compared to the same periods of the prior year.

International E&P

Liquid hydrocarbons – Our international crude oil production is relatively sweet and is generally sold in relation to the Brent crude benchmark, which was 5 percent lower in both the second quarter and first six months of 2013 than the same periods of 2012.

Natural gas – Our major international natural gas-producing regions are Europe and Equatorial Guinea. Natural gas prices in Europe have been considerably higher than in the U.S. in recent years. 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

The Oil Sands Mining segment produces and sells various qualities of synthetic crude oil. Output mix can be impacted by operational problems or planned unit outages at the mines or upgrader. Sales prices for roughly two-thirds of the normal output mix will track movements in WTI and one-third will track movements in the Canadian heavy sour crude oil marker, primarily Western Canadian Select ("WCS"). A decrease in the WTI benchmark prices, coupled with a higher WCS discount from WTI in the first six months of 2013 compared to same period of 2012, created downward pressure on our average realizations. However, in the second quarter of 2013 compared to the second quarter of 2012, the WCS discount from WTI has narrowed, with the discount remaining at these lower levels into July 2013.

The operating cost structure of the Oil Sands Mining operations is predominantly fixed and therefore many of the costs incurred in times of full operation continue during production downtime. Per-unit costs are sensitive to production rates. 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 oil prices, respectively.

The table below shows benchmark prices that impacted both our revenues and variable costs for the second quarter and first six months of 2013 and 2012:

	Three Months Ended June 30,		Six Months Ended June 30,	
Benchmark	2013	2012	2013	2012
WTI crude oil (Dollars per barrel)	$94.17	$93.35	$94.26	$98.15
WCS crude oil (Dollars per barrel)[(a)]	$75.06	$70.63	$68.74	$76.07
AECO natural gas sales index (Dollars per mmbtu)[(b)]	$3.45	$1.84	$3.31	$2.04

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

(b) Monthly average AECO day ahead index.

Results of Operations

Consolidated Results of Operation

Consolidated income before income taxes in the second quarter and first six months of 2013 was approximately 6 percent higher than in the same periods of 2012 primarily related to increases in sales volumes. The effective tax rate was 72 percent in the first six months of 2013 compared to 71 percent in the first six months of 2012, with the increase related to higher income from operations in higher tax jurisdictions, primarily Libya.

Sales and other operating revenues, including related party are summarized by segment in the following table:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2013	2012	2013	2012
Sales and other operating revenues, including related party:				
North America E&P	$1,284	$833	$2,499	$1,745
International E&P	1,732	1,813	3,619	3,476
Oil Sands Mining	353	329	741	698
Segment sales and other operating revenues, including related party	$3,369	$2,975	$6,859	$5,919
Unrealized gain (loss) on crude oil derivative instruments	50	—	—	—
Total sales and other operating revenues, including related party	$3,419	$2,975	$6,859	$5,919

Total sales and other operating revenues increased $444 million and $940 million in the second quarter and first six months of 2013 from the comparable prior-year periods. The $451 million and $754 million increases in the North America E&P segment in the second quarter and first six months of 2013 were primarily due to liquid hydrocarbon net sales volumes which increased 59 percent over the same periods of 2012, primarily due to ongoing development programs in the Eagle Ford and Bakken shale resources plays.

The following table gives details of net sales volumes and average realizations of our North America E&P segment.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
North America E&P Operating Statistics				
Net liquid hydrocarbon sales volumes (mbbld) [(a)]	148	93	145	91
Liquid hydrocarbon average realizations (per bbl) [(b) (c)]	$84.51	$84.72	$85.30	$89.23
Net crude oil and condensate sales volumes (mbbld)	126	85	124	83
Crude oil and condensate average realizations (per bbl) [(b)]	$93.75	$89.04	$94.20	$93.25
Net natural gas liquids sales volumes (mbbld)	22	8	21	8
Natural gas liquids average realizations (per bbl) [(b)]	$31.72	$40.54	$33.51	$45.65
Net natural gas sales volumes (mmcfd)	316	319	328	331
Natural gas average realizations (per mcf)[(b)]	$4.19	$3.42	$4.02	$3.79

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

(b) Excludes gains and losses on derivative instruments

(c) Inclusion of realized gains (losses) on crude oil derivative instruments would have increased average liquid hydrocarbon realizations by $1.22 per bbl and $0.45 per bbl for the second quarter and first six months of 2013. There were no realized gains (losses) on crude oil derivative instruments in the second quarter and first six months of 2012.

As compared to prior year periods, International E&P sales and other operating revenues decreased $81 million in the second quarter of 2013 due to lower liquid hydrocarbon realizations and increased $143 million in the first six months of 2013 as a result of increased liquid hydrocarbon and natural gas sales volumes, partially offset by lower liquid hydrocarbon realizations.

The following table gives details of net sales volumes and average realizations of our International E&P segment.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
International E&P Operating Statistics				
Net liquid hydrocarbon sales volumes (mbbld)[(a)]				
Europe	93	99	96	98
Africa	84	78	82	65
Total International E&P	177	177	178	163
Liquid hydrocarbon average realizations (per bbl)[(b)]				
Europe	$106.41	$111.12	$111.43	$117.37
Africa	$92.92	$96.84	$94.96	$95.87
Total International E&P	$100.00	$104.82	$103.86	$108.80
Net natural gas sales volumes (mmcfd)				
Europe[(c)]	89	102	92	103
Africa	425	399	449	409
Total International E&P	514	501	541	512
Natural gas average realizations (per mcf)[(b)]				
Europe	$11.37	$10.05	$12.12	$10.02
Africa	$0.49	$0.25	$0.50	$0.25
Total International E&P	$2.37	$2.25	$2.47	$2.22

(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 8 mmcfd and 17 mmcfd for the second quarters of 2013 and 2012, and 10 mmcfd and 15 mmcfd for the first six months of 2013 and 2012.

Oil Sands Mining sales and other operating revenues increased $24 million and $43 million in the second quarter and first six months of 2013 from the comparable prior-year periods. Synthetic crude oil sales volumes were slightly lower in the second quarter of 2013 than in the second quarter of 2012; however, a decrease in the discount of WCS to WTI in second quarter of 2013 resulted in increases in average realizations compared to the prior-year period. Synthetic crude oil sales volumes for the first six months of 2013 were 7 percent higher than in the first six months of 2012, reflecting increased reliability of the mines and upgrader in the first quarter of 2013. The following table gives details of net sales volumes and average realizations of our Oil Sands Mining segment.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Oil Sands Mining Operating Statistics				
Net synthetic crude oil sales volumes (mbbld) [(a)]	43	44	47	44
Synthetic crude oil average realizations (per bbl)	$89.39	$79.31	$84.31	$85.07

(a) Includes blendstocks.

Unrealized gains and losses on crude oil derivative instruments are included in total sales and other operating revenues but are not allocated to the segments. In the second quarter of 2013, the net unrealized gain on crude oil derivative instruments was $50 million while unrealized gains and losses did not have a significant impact on the first six months of 2013. There was no comparable crude oil derivative activity in the same periods of 2012. See Note 13 to the consolidated financial statements and Item 3. Quantitative and Qualitative Disclosures About Market Risk for additional information about our derivative positions.

Marketing revenues decreased $258 million and $677 million in the second quarter and first six months of 2013 from the comparable prior-year periods. North America E&P segment marketing activities, formerly referred to as supply optimization activities, which include the purchase of commodities from third parties for resale, have been decreasing in 2013 due to market dynamics. These activities serve to aggregate volumes in order to satisfy transportation commitments and to achieve flexibility within product types and delivery points.

Income from equity method investments increased $17 million and $57 million in the second quarter and first six months of 2013 from the comparable prior-year periods, primarily due to higher LNG net sales volumes.

Net gain (loss) on disposal of assets in the second quarter of 2013 includes a $114 million loss on the sale of our interests in the DJ Basin. In addition, the first six months of 2013 include a $98 million gain on the sale of our interest in the Neptune gas plant, a $55 million gain on the sale of our remaining assets in Alaska and a $43 million loss on the conveyance of our interests in the Marcellus natural gas shale play to the operator. The net loss on disposal of assets in the second quarter of 2012 reflects $36 million to settle all obligations as a result of the assignment of exploration licenses in Indonesia. The net gain on disposal of assets in the first six 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, and the second quarter Indonesia loss. See Note 5 to the consolidated financial statements for information about these dispositions.

Production expenses increased $129 million and $205 million in the second quarter and first six months of 2013 from the comparable periods of 2012. The increases are primarily related to increased sales volumes in the North America E&P and International E&P segments and a planned turnaround in the OSM segment during the second quarter of 2013.

Marketing expenses decreased $260 million and $685 million in the second quarter and first six months of 2013 from the same periods of 2012, consistent with the marketing revenue decline discussed above.

Exploration expenses were lower in the second quarter of 2013 than in the same quarter in 2012 due to lower dry well costs and geological and geophysical costs. Exploration costs were higher in the first six months of 2013 than in the same period of 2012, primarily due to larger unproved property impairments. The first quarter of 2013 included $340 million in unproved property impairments on Eagle Ford shale leases that either have expired or that we do not expect to drill or extend. The following table summarizes the components of exploration expenses.

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2013	2012	2013	2012
Unproved property impairments	$40	$35	$423	$70
Dry well costs	50	81	71	104
Geological and geophysical	12	29	39	74
Other	31	27	65	59
Total exploration expenses	$133	$172	$598	$307

Depreciation, depletion and amortization (“DD&A”) increased $158 million and $331 million in the second quarter and first six months of 2013 from the comparable prior-year periods. Our segments apply the units-of-production method to the majority of their assets; therefore, 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. An increase in the North America E&P DD&A rate in the second quarter and first six months of 2013 compared to the same prior-year periods was primarily due to the ongoing development programs in the Eagle Ford and Bakken shale resources plays. A lower International E&P DD&A rate in the second quarter and first six months of 2013, primarily due to reserve increases at the end of 2012 and in the second quarter of 2013 for Norway, compared to the same periods in 2012 partially offset the impact of the higher North America E&P rate and higher sales volumes. The following table provides DD&A rates for each segment.

	Three Months Ended June 30,		Six Months Ended June 30,	
($ per boe)	2013	2012	2013	2012
DD&A rate				
North America E&P	$27	$22	$27	$23
International E&P	$8	$10	$8	$9

Oil Sands Mining	$12	$13	$12	$13

Impairments in the first six months of 2013 related to the Powder River Basin and to the Ozona development in the Gulf of Mexico. Impairments in the first six months of 2012 were also related to the Ozona development in the Gulf of Mexico. See Note 12 to the consolidated financial statements for information about these impairments.

Taxes other than income include production, severance and ad valorem taxes in the United States which tend to increase or decrease in relation to sales volumes and revenues.

General and administrative expenses increased $10 million and $25 million in the second quarter and first six months of 2013 from the comparable prior year periods primarily due to pension settlement charges of $17 million in the second quarter of 2013.

Net interest and other increased $14 million and $36 million in the second quarter and first six months of 2013 from the comparable periods of 2012 primarily due to lower capitalized interest in 2013.

Provision for income taxes increased $53 million and $151 million in the second quarter and first six months of 2013 from the comparable periods of 2012 primarily due to the increase in pretax income.

The effective income tax rate is influenced by a variety of factors including the geographic 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 items not allocated to segments is shown in corporate and other unallocated items in the segment income table below.

Our effective tax rates in the first six months of 2013 and 2012 were 72 percent and 71 percent. These rates are higher than the U.S. statutory rate of 35 percent due to earnings from foreign jurisdictions, primarily Norway and Libya, where the tax rates are in excess of the U.S. statutory rate. In Libya, where the statutory tax rate is in excess of 90 percent, there remains uncertainty around sustained production and sales levels. Reliable estimates of 2013 and 2012 annual ordinary income from our Libyan operations could not 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 six months of 2013 and 2012, estimated annual effective tax rates were 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 periods. Excluding Libya, the effective tax rates would be 63 percent and 64 percent for the first six months of 2013 and 2012.

Segment Income

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2013	2012	2013	2012
North America E&P	$221	$70	$162	$174
International E&P	382	373	835	780
Oil Sands Mining	20	50	58	88
Segment income	623	493	1,055	1,042
Items not allocated to segments, net of income taxes:				
Corporate and other unallocated items	(156)	(77)	(227)	(148)
Unrealized gain (loss) on crude oil derivative instruments	32	—	—	—
Net gain (loss) on dispositions	(73)	(23)	(9)	83
Impairments	—	—	(10)	(167)
Net income	$426	$393	$809	$810

North America E&P segment income increased $151 million in the second quarter of 2013 and decreased $12 million in the first six months of 2013 compared to the same periods of 2012. The increase in the second quarter of 2013 is largely due to increased liquid hydrocarbon net sales volumes primarily in the Eagle Ford and Bakken shale resource plays. The decrease in the first six months of 2013 was primarily the result of unproved property impairments, higher DD&A and lower liquid hydrocarbon realizations, partially offset by higher liquid hydrocarbon net sales volumes, as discussed above.

International E&P segment income increased $9 million and $55 million in the second quarter and first six months of 2013 compared to the same periods of 2012. These increases were primarily related to higher liquid hydrocarbon net sales volumes and increased income from equity method investments, partially offset by higher income taxes.

Oil Sands Mining segment income decreased $30 million in the second quarter and first six months of 2013 compared to the same periods of 2012. These decreases are primarily due to higher production expenses, including the costs of the scheduled upgrader turnaround in the second quarter of 2013.

Critical Accounting Estimates

There have been no changes to our critical accounting estimates subsequent to December 31, 2012.

Accounting Standards Not Yet Adopted

In June 2013, the Financial Accounting Standards Board ("FASB") ratified the Emerging Issues Task Force consensus on Issue 13-C, which requires that an unrecognized tax benefit or a portion of an unrecognized tax benefit be presented as a reduction to a deferred tax asset for an available net operating loss carryforward, a similar tax loss or tax credit carryforward. This accounting standards update is effective for us beginning in the first quarter of 2014 and should be applied prospectively to unrecognized tax benefits that exist as of the effective date. Early adoption and retrospective application are permitted. We do not expect this accounting standards update to have a significant impact on our consolidated results of operations, financial position or cash flows.

In February 2013, an accounting standards update was issued to provide guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date, except for obligations such as asset retirement and environmental obligations, contingencies, guarantees, income taxes and retirement benefits, which are separately addressed within United States generally accepted accounting principles ("U.S. GAAP"). An entity is required to measure obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date as the sum of 1) the amount the entity agreed to pay on the basis of its arrangement among its co-obligors and 2) any amount the entity expects to pay on behalf of its co-obligors. Disclosure of the nature of the obligation, including how the liability arose, the relationship with other co-obligors and the terms and conditions of the arrangement is required. In addition, the total outstanding amount under the arrangement, not reduced by the effect of any amounts that may be recoverable from other entities, plus the carrying amount of any liability or receivable recognized must be disclosed. This accounting standards update is effective for us beginning in the first quarter of 2014 and should be applied retrospectively for those in-scope obligations resulting from joint and several liability arrangements that exist at the beginning of 2014. Early adoption is permitted. We do not expect this accounting standards update to have a significant impact on our consolidated results of operations, financial position or cash flows.

Cash Flows and Liquidity

Cash Flows

Net cash provided by operating activities was $2,396 million in the first six months of 2013, compared to $1,742 million in the first six months of 2012, primarily reflecting the impact of increased liquid hydrocarbon, natural gas and synthetic crude oil sales volumes on operating income.

Net cash used in investing activities totaled $2,299 million in the first six months of 2013, compared to $2,001 million in the first six months of 2012. Significant investing activities are additions to property, plant and equipment and disposal of assets. Additions in both periods primarily related to spending on U.S. unconventional resource plays, particularly the Eagle Ford shale. Disposals of assets totaled $333 million and $218 million in first six months of 2013 and 2012, with 2013 net proceeds primarily related to the sales of our interests in our Alaska assets, the Neptune gas plant, and the DJ Basin. In 2012, net proceeds resulted primarily from the sale of our interests in several Gulf of Mexico crude oil pipeline systems.

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

Net cash used in financing activities was $543 million in the first six months of 2013, compared to $210 million provided by financing activities in the first six months of 2012. Repayments of debt at maturity were $148 million in the first six months of 2013 and $111 million in the first six months of 2012. We also repaid a net $200 million of our outstanding commercial paper during the first six months of 2013 compared to the same period in 2012, when we drew a net $550 million of commercial paper. Dividends paid of approximately $241 million 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. Because of the alternatives available to us as discussed above, we believe that our short-term and long-term liquidity is adequate to fund not only our current operations, but also our near-term and long-term funding requirements including our capital spending programs, dividend payments, defined benefit plan contributions, repayment of debt maturities, share repurchase program and other amounts that may ultimately be paid in connection with contingencies.

Capital Resources

Credit Arrangements and Borrowings

At June 30, 2013, we had no borrowings against our revolving credit facility or under our U.S. commercial paper program that is backed by the revolving credit facility. During the first six months of 2013, $2,075 million of commercial paper was issued and $2,275 million of commercial paper was repaid.

At June 30, 2013, we had $6,496 million in long-term debt outstanding, $68 million of which is due within one year. We do not have any triggers on any of our corporate debt that would cause an event of default in the case of a downgrade of our credit ratings.

The sale of our non-operated 10 percent working interest in Block 31 offshore Angola, a transaction valued at $1.5 billion before closing adjustments, is expected to close in the fourth quarter of 2013, subject to government, regulatory and third-party approvals. We expect to use the proceeds from this sale principally to repurchase shares, but also to strengthen our balance sheet and for general corporate purposes.

Shelf Registration

We are a "well-known seasoned issuer" for purposes of SEC rules, thereby allowing us to use a universal shelf registration statement should we choose to issue and sell various types of equity and debt securities. Beginning in the first quarter of 2013, we changed our reportable segments and expect to recast all periods presented to reflect these new segments in our consolidated financial statements no later than upon filing our 2013 Annual Report on Form 10-K with the SEC. When appropriate, we will update and file our universal shelf registration statement.

Cash-Adjusted Debt-To-Capital Ratio

Our cash-adjusted debt-to-capital ratio (total debt-minus-cash to total debt-plus-equity-minus-cash) was 25 percent at June 30, 2013 and December 31, 2012.

(In millions)	June 30, 2013	December 31, 2012
Commercial paper	$—	$200
Long-term debt due within one year	68	184
Long-term debt	6,428	6,512
Total debt	$6,496	$6,896
Cash	$246	$684
Equity	$19,021	$18,283
Calculation:		
Total debt	$6,496	$6,896
Minus cash	246	684
Total debt minus cash	6,250	6,212
Total debt	6,496	6,896
Plus equity	19,021	18,283
Minus cash	246	684
Total debt plus equity minus cash	$25,271	$24,495
Cash-adjusted debt-to-capital ratio	25 %	25 %

Capital Requirements

On July 31, 2013, our Board of Directors approved a dividend of 19 cents per share for the second quarter of 2013, a 12 percent increase over the previous quarter, payable September 10, 2013 to stockholders of record at the close of business on August 21, 2013.

As of June 30, 2013, we plan to make contributions of up to $39 million to our funded pension plans during the remainder of 2013.

Since January 2006, our Board of Directors has authorized a common share repurchase program totaling $5 billion. As of June 30, 2013, we had repurchased 78 million common shares at a cost of $3,222 million, with 66 million shares purchased for $2,922 million prior to the spin-off of our downstream business and 12 million shares acquired at a cost of $300 million in the third quarter of 2011. Purchases under the program may be in either open market transactions, including block purchases, or in

privately negotiated transactions. This program may be changed based upon our financial condition or changes in market conditions and is subject to termination prior to completion. The program's authorization does not include specific price targets or timetables. The timing of purchases under the program will be influenced by cash generated from operations, proceeds from potential asset sales, cash from available borrowings and market conditions.

Our opinions concerning liquidity and our ability to avail ourselves in the future of the financing options mentioned in the above forward-looking statements are based on currently available information. If this information proves to be inaccurate, future availability of financing may be adversely affected. 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 discussion of liquidity above also contains forward-looking statements regarding the timing of closing the sale of our 10 percent working interest in Block 31 offshore Angola, including the use of proceeds. The timing of closing the sale of our 10 percent working interest in Block 31 offshore Angola is subject to the satisfaction of customary closing conditions and obtaining necessary government, regulatory and third-party approvals. The expectations with respect to the use of proceeds from the sale of our 10 percent working interest in Block 31 offshore Angola could be affected by changes in the prices and demand for liquid hydrocarbons and natural gas, actions of competitors, disruptions or interruptions of the our exploration or production operations, unforeseen hazards such as weather conditions or acts of war or terrorist acts and other operating and economic considerations. The discussion of liquidity above also contains forward-looking statements regarding planned funding of pension plans, which are based on current expectations, estimates and projections and are not guarantees of actual performance. Actual results may differ materially from these expectations, estimates and projections and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. Some factors that could cause actual results to differ materially include prices of and demand for liquid hydrocarbons, natural gas and synthetic crude oil, actions of competitors, disruptions or interruptions of our production or oil sands mining and bitumen upgrading 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

As of June 30, 2013, our total contractual cash obligations were consistent with December 31, 2012.

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, 2012.

Other Contingencies

We are a 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.

See Part II Item 1. Legal Proceedings for updated information about ongoing litigation.

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 2012 Annual Report on Form 10-K. Additional disclosures regarding our open derivative positions, including underlying notional quantities, how they are reported in our consolidated financial statements and how their fair values are measured, may be found in Notes 12 and 13 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 June 30, 2013 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	$(81)	$(203)	$81	$203
Option Collars	(30)	(92)	34	109
Total crude oil	$(111)	$(295)	$115	$312

Sensitivity analysis of the projected incremental effect of a hypothetical 10 percent change in interest rates on financial assets and liabilities as of June 30, 2013 is provided in the following table.

(In millions)	Fair Value		Incremental Change in Fair Value
Financial assets (liabilities): [(a)]			
Interest rate swap agreements	$6	[(b)]	$3
Long-term debt, including amounts due within one year	$(6,991)	[(b)]	$(241)

(a) Fair values of cash and cash equivalents, receivables, 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 June 30, 2013 would be $49 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 Rules 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. Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our company's design and operation of disclosure controls and procedures were effective as of June 30, 2013.

In the first quarter of 2013, we completed the update of our existing Enterprise Resource Planning ("ERP") system. This update included a new general ledger, consolidations system and reporting tools. 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 June 30,		Six Months Ended June 30,	
(In millions)	2013	2012	2013	2012
Segment Income				
North America E&P	$221	$70	$162	$174
International E&P	382	373	835	780
Oil Sands Mining	20	50	58	88
Segment income	623	493	1,055	1,042
Items not allocated to segments, net of income taxes	(197)	(100)	(246)	(232)
Net income	$426	$393	$809	$810
Capital Expenditures[a]				
North America E&P	$904	$1,013	$1,874	$1,842
International E&P	241	202	466	340
Oil Sands Mining	97	43	142	95
Corporate	15	19	45	63
Total	$1,257	$1,277	$2,527	$2,340
Exploration Expenses				
North America E&P	$76	$147	$511	$253
International E&P	57	25	87	54
Total	$133	$172	$598	$307

[a] Capital expenditures include changes in accruals.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
Net Sales Volumes	2013	2012	2013	2012
North America E&P				
Crude Oil and Condensate (mbbld)	126	85	124	83
Natural Gas Liquids (mbbld)	22	8	21	8
Total Liquid Hydrocarbons	148	93	145	91
Natural Gas (mmcfd)	316	319	328	331
Total North America E&P (mboed)	201	146	200	146
International E&P				
Liquid Hydrocarbons (mbbld)				
Europe	93	99	96	98
Africa	84	78	82	65
Total Liquid Hydrocarbons	177	177	178	163
Natural Gas (mmcfd)				
Europe[b]	89	102	92	103
Africa	425	399	449	409
Total Natural Gas	514	501	541	512
Total International E&P (mboed)	262	261	268	249
Oil Sands Mining				
Synthetic Crude Oil (mbbld)[c]	43	44	47	44
Total Company (mboed)	506	451	515	439
Net Sales Volumes of Equity Method Investees				
LNG (mtd)	5,820	5,467	6,301	5,879
Methanol (mtd)	973	1,268	1,191	1,290

(b) Includes natural gas acquired for injection and subsequent resale of 8 mmcfd and 17 mmcfd for the second quarters of 2013 and 2012, and 10 mmcfd and 15 mmcfd for the first six months of 2013 and 2012.

(c) Includes blendstocks.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

Average Realizations[d]	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
North America E&P				
Crude Oil and Condensate (per bbl)	$93.75	$89.04	$94.20	$93.25
Natural Gas Liquids (per bbl)	$31.72	$40.54	$33.51	$45.65
Total Liquid Hydrocarbons[e]	$84.51	$84.72	$85.30	$89.23
Natural Gas (per mcf)	$4.19	$3.42	$4.02	$3.79
International E&P				
Liquid Hydrocarbons (per bbl)				
Europe	$106.41	$111.12	$111.43	$117.37
Africa	$92.92	$96.84	$94.96	$95.87
Total Liquid Hydrocarbons	$100.00	$104.82	$103.86	$108.80
Natural Gas (per mcf)				
Europe	$11.37	$10.05	$12.12	$10.02
Africa[f]	$0.49	$0.25	$0.50	$0.25
Total Natural Gas	$2.37	$2.25	$2.47	$2.22
Oil Sands Mining				
Synthetic Crude Oil (per bbl)	$89.39	$79.31	$84.31	$85.07

(d) Excludes gains and losses on derivative instruments.

(e) Inclusion of realized gains (losses) on crude oil derivative instruments would have increased average liquid hydrocarbon realizations by $1.22 per bbl and $0.45 per bbl for the second quarter and first six months of 2013. There were no realized gains (losses) on crude oil derivative instruments in the same periods of 2012.

(f) Primarily represents fixed prices under long-term contracts with Alba Plant LLC, Atlantic Methanol Production Company LLC and Equatorial Guinea LNG Holdings Limited, which are equity method investees. We include our share of income from each of these equity method investees in our International E&P segment.

Part II – OTHER INFORMATION
Item 1. Legal Proceedings
We are a 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 those 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. In April 2013, we filed a counterclaim against Noble alleging, among other things, breach of contract and breach of the duty of good faith relating to the multi-year drilling contract. The counterclaim also included a breach of contract claim for reimbursement for the value of fuel used by Noble under an offshore daywork drilling contract. We are vigorously defending this litigation. The ultimate outcome of this lawsuit, including any financial effect on us, remains uncertain. We do not believe an estimate of a reasonably probable loss (or range of loss) can be made for this lawsuit at this time.
Environmental
We executed a settlement agreement with the North Dakota Department of Health regarding voluntary disclosures of potential Clean Air Act violations made in 2009 relating to our operations on state lands in the Bakken shale and paid a fine of $169,800 in June 2013.
SEC Investigation Relating to Libya
On May 25, 2011, we received a subpoena issued by the SEC requiring production of documents related to payments made to the government of Libya, or to officials and persons affiliated with officials of the government of Libya. By letter dated April 26, 2013, the SEC further notified us that they completed their investigation and did not intend to recommend any enforcement action in this matter.
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 2012 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 June 30, 2013, of equity securities that are registered by Marathon Oil pursuant to Section 12 of the Securities Exchange Act of 1934.

	Column (a)	Column (b)	Column (c)	Column (d)
Period	Total Number of Shares Purchased [(a)(b)]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[(c)]	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs[(c)]
04/01/13 - 04/30/13	12,135	$33.64	—	$1,780,609,536
05/01/13 - 05/31/13	3,795	$32.05	—	$1,780,609,536
06/01/13 - 06/30/13	36,664	$34.84	—	$1,780,609,536
Total	52,594	$34.36	—	

(a) 27,051 shares of restricted stock were delivered by employees to Marathon Oil, upon vesting, to satisfy tax withholding requirements.
(b) In June 2013, 25,543 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 June 30, 2013, 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	Restated Certificate of Incorporation of Marathon Oil Corporation.					X	
3.2	Amended By-laws of Marathon Oil Corporation effective May 29, 2013.					X	
3.3	Amended By-Laws of Marathon Oil Corporation effective August 1, 2013.					X	
10.1	Marathon Oil Corporation 2011 Officer Change in Control Severance Benefits Plan (For Officers Hired or Promoted after October 26, 2011).	10-Q	10.4	5/4/2012	001-05153		
12.1	Computation of Ratio of Earnings to Fixed Charges.					X	
31.1	Certification of 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 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.CAL	XBRL Taxonomy Extension Calculation Linkbase.					X	
101.DEF	XBRL Taxonomy Extension Definition Linkbase.					X	
101.LAB	XBRL Taxonomy Extension Label Linkbase.					X	
101.PRE	XBRL Taxonomy Extension Presentation 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.

August 8, 2013 MARATHON OIL CORPORATION

By: /s/ Michael K. Stewart
Michael K. Stewart
Vice President, Finance and Accounting,
Controller and Treasurer

Exhibit Index

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