MARATHON OIL CORP
Form 10-Q
November 07, 2008

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

FORM 10-Q

(Mark One)

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Quarterly Period Ended September 30, 2008

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____ to _____

Commission file number 1-5153

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

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

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

(713) 629-6600
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ü No

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

Large accelerated filer ü Accelerated filer

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

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

There were 705,576,258 shares of Marathon Oil Corporation common stock outstanding as of October 31, 2008.

MARATHON OIL CORPORATION

Form 10-Q

Quarter Ended September 30, 2008

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Unless the context otherwise indicates, references in this Form 10-Q to “Marathon,” “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 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)

(In millions, except per share data)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Revenues and other income:				
Sales and other operating revenues (including consumer excise taxes)	$ 22,477	$ 16,347	$ 60,983	$ 45,221
Sales to related parties	637	415	1,865	1,146
Income from equity method investments	270	170	735	394
Net gain on disposal of assets	15	2	37	20
Other income	47	20	151	62
Total revenues and other income	23,446	16,954	63,771	46,843
Costs and expenses:				
Cost of revenues (excludes items below)	16,992	12,951	49,432	34,358
Purchases from related parties	244	104	609	240
Consumer excise taxes	1,273	1,352	3,784	3,856
Depreciation, depletion and amortization	597	409	1,552	1,198
Selling, general and administrative expenses	351	336	1,012	950
Other taxes	126	95	376	286
Exploration expenses	109	88	368	264
Total costs and expenses	19,692	15,335	57,133	41,152
Income from operations	3,754	1,619	6,638	5,691
Net interest and other financing income (costs)	(53)	19	(54)	58
Gain on foreign currency derivative instruments	-	120	-	120
Loss on early extinguishment of debt	-	(11)	-	(14)
Minority interests in loss of Equatorial Guinea LNG Holdings Limited	-	-	-	3
Income from continuing operations before income taxes	3,701	1,747	6,584	5,858
Provision for income taxes	1,637	726	3,015	2,578
Income from continuing operations	2,064	1,021	3,569	3,280

Discontinued operations	-	-	-	8
Net income	$ 2,064	$ 1,021	$ 3,569	$ 3,288
Per Share Data				
Basic:				
Income from continuing operations	$ 2.92	$ 1.50	$ 5.03	$ 4.80
Discontinued operations	$ -	$ -	$ -	$ 0.01
Net income	$ 2.92	$ 1.50	$ 5.03	$ 4.81
Diluted:				
Income from continuing operations	$ 2.90	$ 1.49	$ 5.00	$ 4.76
Discontinued operations	$ -	$ -	$ -	$ 0.01
Net income	$ 2.90	$ 1.49	$ 5.00	$ 4.77
Dividends	$ 0.24	$ 0.24	$ 0.72	$ 0.68

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

MARATHON OIL CORPORATION
Consolidated Balance Sheets (Unaudited)

(In millions, except per share data)		September 30, 2008		December 31, 2007
Assets				
Current assets:				
Cash and cash equivalents	$	1,479	$	1,199
Receivables, less allowance for doubtful accounts of $4 and $3		6,094		5,818
Receivables from United States Steel		23		22
Receivables from related parties		115		79
Inventories		4,446		3,277
Other current assets		216		192
Total current assets		12,373		10,587
Equity method investments		2,827		2,630
Receivables from United States Steel		469		485
Property, plant and equipment, less accumulated depreciation, depletion and amortization of $16,152 and $14,857		28,129		24,675
Goodwill		2,887		2,899
Intangible assets, less accumulated amortization of $93 and $80		279		288
Other noncurrent assets		1,942		1,182
Total assets	$	48,906	$	42,746
Liabilities				
Current liabilities:				
Short-term debt	$	1,290	$	-
Accounts payable and accrued liabilities		8,975		8,281
Payables to related parties		40		44
Payroll and benefits payable		364		417
Accrued taxes		992		712
Deferred income taxes		397		547
Accrued interest		131		128
Long-term debt due within one year		88		1,131
Total current liabilities		12,277		11,260
Long-term debt		7,074		6,084
Deferred income taxes		4,873		3,389
Defined benefit postretirement plan obligations		1,205		1,092
Asset retirement obligations		1,135		1,131
Payable to United States Steel		4		5
Deferred credits and other liabilities		411		562
Total liabilities		26,979		23,523
Commitments and contingencies				
Stockholders' Equity				

Preferred stock – 5 million shares issued, 3 million and 5 million shares				
outstanding (no par value, 6 million shares authorized)		-		-
Common stock:				
Issued – 767 million and 765 million shares (par value $1 per share,				
1.1 billion shares authorized)		767		765
Securities exchangeable into common stock – 5 million shares issued,				
3 million and 5 million shares outstanding (no par value, unlimited				
shares authorized)		-		-
Held in treasury, at cost – 61 million and 55 million shares		(2,722)		(2,384)
Additional paid-in capital		6,686		6,679
Retained earnings		17,470		14,412
Accumulated other comprehensive loss		(274)		(249)
Total stockholders' equity		21,927		19,223
Total liabilities and stockholders' equity	$	48,906	$	42,746

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)

(In millions)	Nine Months Ended September 30, 2008	2007
Increase (decrease) in cash and cash equivalents		
Operating activities:		
Net income	$ 3,569	$ 3,288
Adjustments to reconcile net income to net cash provided by operating activities:		
Loss on early extinguishment of debt	-	14
Income from discontinued operations	-	(8)
Deferred income taxes	314	12
Minority interests in loss of Equatorial Guinea LNG Holdings Limited	-	(3)
Depreciation, depletion and amortization	1,552	1,198
Pension and other postretirement benefits, net	115	68
Exploratory dry well costs and unproved property impairments	154	109
Net gain on disposal of assets	(37)	(20)
Equity method investments, net	(139)	(123)
Changes in the fair value of U.K. natural gas contracts	37	111
Changes in:		
Current receivables	(287)	(1,190)
Inventories	(1,173)	(1,444)
Current accounts payable and accrued liabilities	703	988
All other, net	(1)	(49)
Net cash provided by operating activities	4,807	2,951
Investing activities:		
Capital expenditures	(5,168)	(2,725)
Disposal of assets	68	51
Trusteed funds - withdrawals	402	163
Investments - loans and advances	(104)	(88)
Investments - repayments of loans and return of capital	18	35
Deconsolidation of Equatorial Guinea LNG Holdings Limited	-	(37)
All other, net	(16)	(8)
Net cash used in investing activities	(4,800)	(2,609)
Financing activities:		
Short term debt, net	1,288	-
Borrowings	1,248	2,071
Debt issuance costs	(7)	(19)
Debt repayments	(1,331)	(541)
Issuance of common stock	9	23
Purchases of common stock	(402)	(800)
Excess tax benefits from stock-based compensation arrangements	8	25
Dividends paid	(511)	(465)
Contributions from minority shareholders of Equatorial Guinea LNG Holdings Limited	-	39

Net cash provided by financing activities		302		333
Effect of exchange rate changes on cash		(29)		9
Net increase in cash and cash equivalents		280		684
Cash and cash equivalents at beginning of period		1,199		2,585
Cash and cash equivalents at end of period	$	1,479	$	3,269

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 but, in the opinion of management, reflect all adjustments necessary for a fair statement of the results for the periods reported. All such adjustments are of a normal recurring nature unless disclosed otherwise. These consolidated financial statements, including notes, have been prepared in accordance with the applicable rules of the Securities and Exchange Commission and do not include all of the information and disclosures required by accounting principles generally accepted in the United States of America for complete financial statements. Certain reclassifications of prior year data have been made to conform to 2008 classifications. These interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Marathon Oil Corporation ("Marathon" or the "Company") 2007 Annual Report on Form 10-K. The results of operations for the quarter and nine-months ended September 30, 2008 are not necessarily indicative of the results to be expected for the full year.

2. New Accounting Standards

In April 2007, the Financial Accounting Standards Board ("FASB") issued FASB Staff Position ("FSP") FASB Interpretation No. 39 ("FSP FIN 39-1"), "Offsetting of Amounts Related to Certain Contracts", which allows a party to a master netting agreement to offset the fair value amounts related to the right to reclaim collateral against the fair value amounts recognized for derivative instruments. Such treatment was consistent with Marathon's accounting policy; therefore, adoption of FSP FIN No. 39-1 effective January 1, 2008, did not have any effect on our consolidated financial position.

In February 2007, the FASB issued Statement of Financial Accounting Standards ("SFAS") No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities." This statement permits entities to choose to measure at fair value many financial instruments and certain other items that are not currently required to be measured at fair value. It requires that unrealized gains and losses on items for which the fair value option has been elected be recorded in net income. The statement also establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. We did not elect the fair value option when this standard became effective on January 1, 2008.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements." This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 does not require any new fair value measurements but may require some entities to change their measurement practices. In February 2008, the FASB issued FSP FAS 157-1, "Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13," which removes certain leasing transactions from the scope of SFAS No. 157, and FSP FAS 157-2, "Effective Date of FASB Statement No. 157," which defers the effective date of SFAS No. 157 for one year for certain nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis. Effective January 1, 2008, we adopted SFAS No. 157, except for measurements of those nonfinancial assets and liabilities subject to the one-year deferral, which for us includes impairments of goodwill, intangible assets and other long-lived assets, and initial measurement of asset retirement obligations, asset exchanges, business combinations and partial sales of proved properties. Adoption did not have a significant effect on our consolidated results of operations or financial position. The additional disclosures regarding assets and liabilities recorded at fair value and measured under SFAS No. 157 are presented in Note 11.

In October 2008, the FASB issued FSP FAS 157-3, “Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active,” (“FSP FAS 157-3”) which clarifies the application of SFAS No. 157 in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. FSP FAS 157-3 is effective upon issuance, including prior periods for which financial statements have not been issued, and any revisions resulting from a change in the valuation technique or its application shall be accounted for as a change in accounting estimate. Application of FSP FAS 157-3 did not cause us to change our valuation techniques for assets and liabilities measured under SFAS No. 157.

Notes to Consolidated Financial Statements (Unaudited)

3. Income per Common Share

Basic income per share is based on the weighted average number of common shares outstanding, including securities exchangeable into common shares. Diluted income per share includes exercise of stock options and restricted shares, provided the effect is not antidilutive.

	Three Months Ended September 30,			
	2008		2007	
(In millions, except per share data)	Basic	Diluted	Basic	Diluted
Net income	$ 2,064	$ 2,064	$ 1,021	$ 1,021
Weighted average common shares outstanding	707	707	680	680
Effect of dilutive securities	-	4	-	5
Weighted average common shares, including dilutive effect	707	711	680	685
Per share:				
Net income	$ 2.92	$ 2.90	$ 1.50	$ 1.49

	Nine Months Ended September 30,			
	2008		2007	
(In millions, except per share data)	Basic	Diluted	Basic	Diluted
Income from continuing operations	$ 3,569	$ 3,569	$ 3,280	$ 3,280
Discontinued operations	-	-	8	8
Net income	$ 3,569	$ 3,569	$ 3,288	$ 3,288
Weighted average common shares outstanding	710	710	684	684
Effect of dilutive securities	-	4	-	5
Weighted average common shares, including dilutive effect	710	714	684	689
Per share:				
Income from continuing operations	$ 5.03	$ 5.00	$ 4.80	$ 4.76
Discontinued operations	$ -	$ -	$ 0.01	$ 0.01
Net income	$ 5.03	$ 5.00	$ 4.81	$ 4.77

The per share calculations above exclude 5.5 million stock options for the third quarter and the first nine months of 2008 and 3.0 million stock options for the third quarter and the first nine months of 2007, as they were antidilutive.

4. Acquisition

On October 18, 2007, we completed the acquisition of all the outstanding shares of Western Oil Sands Inc. (“Western”) for cash and securities of $5,833 million. Subsequent to the transaction, Western’s name was changed to Marathon Oil Canada Corporation. The acquisition was accounted for under the purchase method of accounting and, as such, our results of operations include Western’s results from October 18, 2007. Western’s oil sands mining and bitumen upgrading operations are reported as a separate Oil Sands Mining segment, while its ownership interests in leases where in-situ recovery techniques are expected to be utilized are included in the Exploration and Production segment.

Notes to Consolidated Financial Statements (Unaudited)

The following shows our unaudited pro forma data as if the acquisition of Western had been consummated at the beginning of each period presented. The pro forma data is based on historical information and does not reflect the actual results that would have occurred nor is it indicative of future results of operations.

(In millions, except per share amounts)	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2007
Revenues and other income	$ 17,246	$ 47,670
Income from continuing operations	1,086	3,102
Net income	1,086	3,110
Per share data:		
Income from continuing operations - basic	$ 1.52	$ 4.32
Income from continuing operations - diluted	$ 1.51	$ 4.29
Net income - basic	$ 1.52	$ 4.33
Net income - diluted	$ 1.51	$ 4.30

5. Segment Information

We have four reportable operating segments:

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

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

3) Refining, Marketing and Transportation ("RM&T") – refines, markets and transports crude oil and petroleum products, primarily in the Midwest, upper Great Plains, Gulf Coast and southeastern regions of the United States; and

4) Integrated Gas ("IG") – markets and transports products manufactured from natural gas, such as liquefied natural gas ("LNG") and methanol, on a worldwide basis, and is developing other projects to link stranded natural gas resources with key demand areas.

(In millions)	E&P	OSM	RM&T	IG	Total
Three Months Ended September 30, 2008					
Revenues:					
Customer	$ 3,584	$ 532	$ 18,139	$ 24	$ 22,279
Intersegment (a)	278	68	1	-	347
Related parties	11	-	626	-	637
Segment revenues	3,873	600	18,766	24	23,263
Elimination of intersegment revenues	(278)	(68)	(1)	-	(347)
Gain on U.K. natural gas contracts	198	-	-	-	198
Total revenues	$ 3,793	$ 532	$ 18,765	$ 24	$ 23,114
Segment income	$ 939	$ 288	$ 771	$ 65	$ 2,063

Income from equity method investments	65	-	115	90	270
Depreciation, depletion and amortization (b)	402	37	148	1	588
Income tax provision (b)	991	98	464	34	1,587
Capital expenditures (c)	738	271	765	3	1,777

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Notes to Consolidated Financial Statements (Unaudited)

(In millions)	E&P	OSM	RM&T	IG	Total
Three Months Ended September 30, 2007					
Revenues:					
Customer	$ 2,318	$ -	$ 14,088	$ 64	$ 16,470
Intersegment (a)	116	-	115	-	231
Related parties	13	-	402	-	415
Segment revenues	2,447	-	14,605	64	17,116
Elimination of intersegment revenues	(116)	-	(115)	-	(231)
Loss on U.K. natural gas contracts	(123)	-	-	-	(123)
Total revenues	$ 2,208	$ -	$ 14,490	$ 64	$ 16,762
Segment income	$ 479	$ -	$ 482	$ 52	$ 1,013
Income from equity method investments	60	-	44	66	170
Depreciation, depletion and amortization (b)	254	-	146	1	401
Income tax provision(b)	544	-	262	8	814
Capital expenditures (c)(d)	582	-	430	2	1,014

(In millions)	E&P	OSM	RM&T	IG	Total
Nine Months Ended September 30, 2008					
Revenues:					
Customer	$ 9,586	$ 631	$ 50,739	$ 64	$ 61,020
Intersegment (a)	663	184	203	-	1,050
Related parties	40	-	1,825	-	1,865
Segment revenues	10,289	815	52,767	64	63,935
Elimination of intersegment revenues	(663)	(184)	(203)	-	(1,050)
Loss on U.K. natural gas contracts	(37)	-	-	-	(37)
Total revenues	$ 9,589	$ 631	$ 52,564	$ 64	$ 62,848
Segment income	$ 2,451	$ 158	$ 854	$ 266	$ 3,729
Income from equity method investments	204	-	186	345	735
Depreciation, depletion and amortization (b)	972	104	446	3	1,525
Income tax provision (b)	2,532	53	527	118	3,230
Capital expenditures (c)(d)	2,387	781	1,978	4	5,150

Notes to Consolidated Financial Statements (Unaudited)

(In millions)	E&P	OSM	RM&T	IG	Total
Nine Months Ended September 30, 2007					
Revenues:					
Customer	$ 6,041	$ -	$ 39,103	$ 188	$ 45,332
Intersegment (a)	372	-	199	-	571
Related parties	24	-	1,122	-	1,146
Segment revenues	6,437	-	40,424	188	47,049
Elimination of intersegment revenues	(372)	-	(199)	-	(571)
Loss on U.K. natural gas contracts	(111)	-	-	-	(111)
Total revenues	$ 5,954	$ -	$ 40,225	$ 188	$ 46,367
Segment income	$ 1,264	$ -	$ 2,073	$ 83	$ 3,420
Income from equity method investments	165	-	116	113	394
Depreciation, depletion and amortization (b)	733	-	436	5	1,174
Minority interest in loss of subsidiary	-	-	-	3	3
Income tax provision (b)	1,438	-	1,181	20	2,639
Capital expenditures (c)(d)	1,623	-	981	93	2,697

(a) Management believes intersegment transactions were conducted under terms comparable to those with unrelated parties.

(b) Differences between segment totals and our totals represent amounts related to corporate administrative activities and other unallocated items and are included in "Items not allocated to segments, net of income taxes" in reconciliation below.

(c) Differences between segment totals and our totals represent amounts related to corporate administrative activities.

(d) Through April 2007, Integrated Gas segment capital expenditures include Equatorial Guinea LNG Holdings Limited ("EGHoldings") at 100 percent. Effective May 1, 2007, we no longer consolidate EGHoldings and our investment in EGHoldings is accounted for under the equity method of accounting; therefore, EGHoldings' capital expenditures subsequent to April 2007 are not included in our capital expenditures.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2008	2007	2008	2007
Segment income	$ 2,063	$ 1,013	$ 3,729	$ 3,420
Items not allocated to segments, net of income taxes:				
Corporate and other unallocated items	(100)	3	(141)	(149)
Gain (loss) on U.K. natural gas contracts	101	(62)	(19)	(56)
	-	74	-	74

Gain on foreign currency derivative instruments (a)								
Loss on early extinguishment of debt		-		(7)		-		(9)
Discontinued operations(b)		-		-		-		8
Net income	$	2,064	$	1,021	$	3,569	$	3,288

(a) Represents unrealized gains in the third quarter 2007 on foreign currency derivative instruments entered into to limit our exposure to the Canadian dollar exchange rate related to the cash portion of the purchase prices for Western Oil Sand Inc.

(b) The Russian businesses sold in June 2006 were accounted for as discontinued operations. Adjustments to the sales price were completed in 2007 and an additional gain on the sale of $8 million ($13 million before income taxes) was recognized. See our 2007 Form 10-K for further information.

Notes to Consolidated Financial Statements (Unaudited)

The following reconciles total revenues to sales and other operating revenues (including consumer excise taxes) as reported in the consolidated statements of income.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2008	2007	2008	2007
Total revenues	$ 23,114	$ 16,762	$ 62,848	$ 46,367
Less: Sales to related parties	637	415	1,865	1,146
Sales and other operating revenues (including consumer excise taxes)	$ 22,477	$ 16,347	$ 60,983	$ 45,221

6. Defined Benefit Postretirement Plans

The following summarizes the components of net periodic benefit cost:

	Three Months Ended September 30,			
	Pension Benefits		Other Benefits	
(In millions)	2008	2007	2008	2007
Service cost	$ 37	$ 35	$ 5	$ 6
Interest cost	40	36	11	11
Expected return on plan assets	(42)	(38)	-	-
Amortization:				
– prior service cost (credit)	3	3	(2)	(2)
– actuarial loss	8	9	-	2
Net periodic benefit cost	$ 46	$ 45	$ 14	$ 17

	Nine Months Ended September 30,			
	Pension Benefits		Other Benefits	
(In millions)	2008	2007	2008	2007
Service cost	$ 110	$ 105	$ 14	$ 17
Interest cost	120	107	33	33
Expected return on plan assets	(126)	(115)	-	-
Amortization:				
– prior service cost (credit)	10	10	(6)	(7)
– actuarial loss	23	27	1	6
Net periodic benefit cost	$ 137	$ 134	$ 42	$ 49

During the first nine months of 2008, we made contributions of $37 million to our funded international pension plans. We expect to make additional contributions of an estimated $32 million to our funded pension plans over the remainder of 2008, with $29 million of that made in October 2008. Contributions made from our general assets to cover current benefit payments related to unfunded pension and other postretirement benefit plans were $14 million and $24 million during the first nine months of 2008.

Notes to Consolidated Financial Statements (Unaudited)

7. Income Taxes

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

	Nine Months Ended September 30, 2008	2007
Statutory U.S. income tax rate	35 %	35 %
Effects of foreign operations, including foreign tax credits	11	8
State and local income taxes, net of federal income tax effects	1	2
Other tax effects	(1)	(1)
Effective income tax rate for continuing operations	46 %	44 %

The geographic sources of income and related tax expense contributed to the increase in the effective income tax rate in the first nine months of 2008 when compared to the same period in 2007. The estimated 2008 effective tax rate is reduced by approximately 4 percent by the reversal of previously recorded valuation allowances on Norwegian net operating losses.

We are continuously undergoing examination of our U.S. federal income tax returns by the Internal Revenue Service. Such audits have been completed through the 2005 tax year. We believe adequate provision has been made for federal income taxes and interest which may become payable for years not yet settled. Further, we are routinely involved in U.S. state income tax audits and foreign jurisdiction tax audits. We believe all other audits will be resolved within the amounts paid and/or provided for these liabilities. As of September 30, 2008, our income tax returns remain subject to examination in the following major tax jurisdictions for the tax years indicated.

United States (a)	2001 - 2007
Canada	2000 - 2007
Equatorial Guinea	2006 - 2007
Libya	2006 - 2007
United Kingdom	2005 - 2007

(a) Includes federal and state jurisdictions.

8. Comprehensive Income

The following sets forth comprehensive income for the periods indicated:

(In millions)	Three Months Ended September 30, 2008	2007	Nine Months Ended September 30, 2008	2007
Net income	$ 2,064	$ 1,021	$ 3,569	$ 3,288
Other comprehensive income, net of taxes:				
Defined benefit postretirement plans (a)	22	7	2	(29)
Other	(26)	10	(27)	12
Comprehensive income	$ 2,060	$ 1,038	$ 3,544	$ 3,271

(a) During the first six months of 2008 and 2007, changes were made to the estimates used to measure certain assumptions necessary in determining the funded status of our postretirement benefit plans as of December 31, 2007 and 2006.

Notes to Consolidated Financial Statements (Unaudited)

9. Inventories

Inventories are carried at the lower of cost or market value. The cost of inventories of crude oil, refined products and merchandise is determined primarily under the last-in, first-out ("LIFO") method.

(In millions)	September 30, 2008	December 31, 2007
Liquid hydrocarbons, natural gas and bitumen	$ 2,303	$ 1,203
Refined products and merchandise	1,847	1,792
Supplies and sundry items	296	282
Total, at cost	$ 4,446	$ 3,277

10. Property, Plant and Equipment

Exploratory well costs capitalized greater than one year after completion of drilling were $54 million as of September 30, 2008, a decrease of $46 million from December 31, 2007, primarily due to the transfer of the Ozona prospect exploratory wells in progress. A well on the Ozona prospect was re-entered and production casing was set in the second quarter of 2008. In October 2008, the development of the Ozona prospect was authorized by our board of directors.

11. Fair Value Measurements

As defined in SFAS No. 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. SFAS No. 157 describes three approaches to measuring the fair value of assets and liabilities: the market approach, the income approach and the cost approach, each of which includes multiple valuation techniques. The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. The income approach uses valuation techniques to measure fair value by converting future amounts, such as cash flows or earnings, into a single present value amount using current market expectations about those future amounts. The cost approach is based on the amount that would currently be required to replace the service capacity of an asset. This is often referred to as current replacement cost. The cost approach assumes that the fair value would not exceed what it would cost a market participant to acquire or construct a substitute asset of comparable utility, adjusted for obsolescence.

SFAS No. 157 does not prescribe which valuation technique should be used when measuring fair value and does not prioritize among the techniques. SFAS No. 157 establishes a fair value hierarchy that prioritizes the inputs used in applying the various valuation techniques. Inputs broadly refer to the assumptions that market participants use to make pricing decisions, including assumptions about risk. Level 1 inputs are given the highest priority in the fair value hierarchy while Level 3 inputs are given the lowest priority. The three levels of the fair value hierarchy are as follows.

- Level 1 – Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

- Level 2 – Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date.

- Level 3 – Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

We use a market or income approach for recurring fair value measurements and endeavor to use the best information available. Accordingly, valuation techniques that maximize the use of observable inputs are favored. Financial assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy.

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The following table presents net financial assets (liabilities) accounted for at fair value on a recurring basis as of September 30, 2008:

(In millions)	Level 1	Level 2	Level 3	Total
Derivative Instruments:				
Commodity	$ 44	$ 6	$ (495)	$ (445)
Interest rate	-	-	3	3
Foreign currency	-	(9)	1	(8)
Total at fair value	$ 44	$ (3)	$ (491)	$ (450)

Deposits of $11 million in broker accounts covered by master netting agreements are netted against the value to arrive at the fair values of commodity derivatives. Derivatives in Level 1 are exchange-traded contracts for crude oil, natural gas, refined products and ethanol measured at fair value with a market approach using the close-of-day settlement prices for the market. Derivatives in Level 2 are measured at fair value with a market approach using broker quotes or third-party pricing services, which have been corroborated with data from active markets. Level 3 derivatives are measured at fair value using either a market or income approach. Generally at least one input is unobservable, such as the use of an internally generated model or an external data source.

Commodity derivatives in Level 3 include a $328 million liability related to two U.K. natural gas sales contracts that are accounted for as derivative instruments and a $131 million liability for crude oil options related to sales of Canadian synthetic crude oil. The fair value of the U.K. natural gas contracts is measured with an income approach by applying the difference between the contract price and the U.K. forward natural gas strip price to the expected sales volumes for the shorter of the remaining contract term or 18 months. These contracts originated in the early 1990s and expire in September 2009. The contract prices are reset annually in October based on the previous twelve-month changes in a basket of energy and other indices. Consequently, the prices under these contracts do not track forward natural gas prices. The crude oil options, which expire December 2009, are measured at fair value using a Black-Scholes option pricing model, an income approach that utilizes prices from an active market and market volatility calculated by a third-party service.

The following is a reconciliation of the net beginning and ending balances recorded for derivative instruments classified as Level 3 in the fair value hierarchy for the three and nine months ended September 30, 2008.

(In millions)	Three Months Ended September 30, 2008
Beginning balance	$ (988)
Total realized and unrealized losses:	
Included in net income	445
Purchases, sales, issuances and settlements, net	52
Ending balance	$ (491)

(In millions)	Nine Months Ended September 30, 2008

Beginning balance	$	(356)
Total realized and unrealized losses:		
Included in net income		(235)
Included in other comprehensive income		1
Purchases, sales, issuances and settlements, net		99
Ending balance	$	(491)

The change in unrealized losses included in net income related to instruments held at September 30, 2008 was a reduction of $413 million and an increase of $126 million for the third quarter and first nine months of 2008. Amounts reported in net income are classified as sales and other operating revenues or cost of revenues for commodity derivative instruments, as net interest and other financing income for interest rate derivative instruments and as cost of revenues for foreign currency derivatives, except those designated as hedges of future

Notes to Consolidated Financial Statements (Unaudited)

capital expenditures. Amounts related to foreign currency derivatives designated as hedges of future capital expenditures accumulate in other comprehensive income and are amortized to depletion, depreciation and amortization on a units-of-production basis over the life of the capital asset.

12. Debt

At September 30, 2008, we had $886 million of commercial paper, at a weighted average interest rate of 5.9 percent, outstanding under our U.S. commercial paper program which is supported by our $3.0 billion revolving credit facility. An additional $404 million in borrowings was outstanding under the revolving credit facility at a weighted average interest rate of 5.0 percent. Neither commercial paper nor borrowings under the revolving credit facility were outstanding at December 31, 2007.

In March 2008, we issued $1 billion aggregate principal amount of senior notes bearing interest at 5.9 percent with a maturity date of March 15, 2018. Interest on the senior notes is payable semi-annually beginning September 15, 2008.

In February 2008, the 805 million Canadian dollar revolving term credit facility of Marathon Oil Canada Corporation was repaid and the facility was terminated.

13. Stock-Based Compensation Plans

The following table presents a summary of stock option award and restricted stock award activity for the nine month period ended September 30, 2008:

	Stock Options		Restricted Stock	
	Number of Shares (a)	Weighted Average Exercise Price	Awards	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2007	12,214,853	$34.58	1,527,831	$39.87
Granted (b)	2,555,218	51.77	1,402,413	48.27
Options Exercised/Stock Vested	(479,632)	23.87	(603,697)	29.47
Canceled	(365,682)	51.68	(117,289)	43.15
Outstanding at September 30, 2008	13,924,757	$37.65	2,209,258	$47.87

(a) Of the stock option awards outstanding as of September 30, 2008, 5,486,987, 7,938,260 and 499,510 were outstanding under the 2007 Incentive Compensation Plan, the 2003 Incentive Compensation Plan and the 1990 Stock Plan, including 749,282 stock options with tandem stock appreciation rights.

(b) The weighted average grant date fair value of stock option awards granted was $13.03 per share.

14. Stockholders' Equity

Share repurchase – As of September 30, 2008, we had acquired 66 million common shares at a cost of $2,922 million under our $5 billion authorized share repurchase program, including 8 million common shares acquired during the first nine months of 2008 at a cost of $402 million.

15. Commitments and Contingencies

We are the subject of, or party to, a number of pending or threatened legal actions, contingencies and commitments involving a variety of matters, including laws and regulations relating to the environment. The ultimate resolution of these contingencies could, individually or in the aggregate, be material to our consolidated financial statements. However, management believes that we will remain a viable and competitive enterprise even though it is possible that these contingencies could be resolved unfavorably. Certain of our commitments are discussed below.

We, along with some other defendants with refinery operations, recently settled a number of lawsuits alleging methyl tertiary butyl ether ("MTBE") contamination of water supply wells. We were a defendant in 40 of the cases settled. Our share of the cash portion of the settlement was paid in October 2008 and did not significantly impact our consolidated results of operations, financial position or cash flows. Under the settlement, the settling

Notes to Consolidated Financial Statements (Unaudited)

defendants, including our company, are responsible for addressing future MTBE contamination in certain water supply wells. We do not expect that our share of liability for any such future obligations under the settlement to significantly impact our consolidated results of operations, financial position or cash flows.

Contractual commitments – At September 30, 2008, Marathon's contract commitments to acquire property, plant and equipment totaled $3,966 million.

16. Supplemental Cash Flow Information

(In millions)	Nine Months Ended September 30, 2008	2007
Net cash provided from operating activities included:		
Interest paid (net of amounts capitalized)	$ 85	$ 66
Income taxes paid to taxing authorities	2,458	2,711
Noncash investing and financing activities:		
Bond obligation assumed for trusteed funds	$ -	$ 1,000
Noncash effect of deconsolidation of EGHoldings:		
Decrease in non-cash assets	$ -	$ 1,759
Record equity method investment	-	942
Decrease in liabilities	-	310
Elimination of minority interest	-	544

17. Accounting Standards Not Yet Adopted

In June 2008, the FASB issued FSP on EITF 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities" ("FSP EITF 03-6-1") which provides that unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and, therefore, need to be included in the earnings allocation in computing earnings per share ("EPS") under the two-class method. FSP EITF 03-6-1 is effective January 1, 2009 and all prior-period EPS data (including any amounts related to interim periods, summaries of earnings and selected financial data) will be adjusted retrospectively to conform to its provisions. Early application of FSP EITF 03-6-1 is not permitted. Although restricted stock awards meet this definition of participating securities, we do not expect application of FSP EITF 03-6-1 to have a significant impact on our reported EPS.

In April 2008, the FASB issued FSP on FAS 142-3 ("FSP FAS 142-3") which amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under SFAS No. 142, "Goodwill and Other Intangible Assets." The intent of this FSP is to improve the consistency between the useful life of a recognized intangible asset and the period of expected cash flows used to measure the fair value of the asset. FSP FAS 142-3 is effective on January 1, 2009, early adoption is prohibited. The provisions of FSP FAS 142-3 are to be applied prospectively to intangible assets acquired after the effective date, except for the disclosure requirements which must be applied prospectively to all intangible assets recognized as of, and subsequent to, the effective date. Since this standard will be applied prospectively, adoption is not expected to have a significant impact on our consolidated results of operations, financial position or cash flows.

In March 2008, the FASB issued SFAS No. 161, “Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133.” This statement expands the disclosure requirements for derivative instruments to provide information regarding (i) how and why an entity uses derivative instruments, (ii) how derivative instruments and related hedged items are accounted for under SFAS No. 133 and its related interpretations and (iii) how derivative instruments and related hedged items affect an entity’s financial position, financial performance and cash flows. To meet these objectives, the statement requires qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts and gains and losses on derivative instruments and disclosures about credit-risk-related contingent features in derivative agreements. This standard is effective January 1, 2009. The statement encourages but does not require disclosures

Notes to Consolidated Financial Statements (Unaudited)

for earlier periods presented for comparative purposes at initial adoption. We will expand our disclosures in accordance with SFAS No. 161 beginning in the first quarter of 2009; however, the adoption of this standard is not expected to have a significant impact on our consolidated results of operations, financial position or cash flows.

In December 2007, the FASB issued SFAS No. 141 (Revised 2007), "Business Combinations" ("SFAS No. 141 (R)"). This statement significantly changes the accounting for business combinations. Under SFAS No.141(R), an acquiring entity will be required to recognize all the assets acquired, liabilities assumed and any non-controlling interest in the acquiree at their acquisition-date fair value with limited exceptions. The statement expands the definition of a business and is expected to be applicable to more transactions than the previous business combinations standard. The statement also changes the accounting treatment for changes in control, step acquisitions, transaction costs, acquired contingent liabilities, in-process research and development, restructuring costs, changes in deferred tax asset valuation allowances as a result of a business combination and changes in income tax uncertainties after the acquisition date. Accounting for changes in valuation allowances for acquired deferred tax assets and the resolution of uncertain tax positions for prior business combinations will impact tax expense instead of impacting recorded goodwill. Additional disclosures are also required. SFAS No. 141(R) is effective on January 1, 2009 for all new business combinations. We are currently evaluating the provisions of this statement.

Also in December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements - An Amendment of ARB No. 51." This statement establishes new accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. Specifically, this statement clarifies that a noncontrolling interest in a subsidiary (sometimes called a minority interest) is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements, but separate from the parent's equity. It requires that the amount of consolidated net income attributable to the noncontrolling interest be clearly identified and presented on the face of the consolidated income statement. SFAS No. 160 clarifies that changes in a parent's ownership interest in a subsidiary that do not result in deconsolidation are equity transactions if the parent retains its controlling financial interest. In addition, this statement requires that a parent recognize a gain or loss in net income when a subsidiary is deconsolidated, based on the fair value of the noncontrolling equity investment on the deconsolidation date. Additional disclosures are required that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS No. 160 is effective January 1, 2009 and early adoption is prohibited. The statement must be applied prospectively, except for the presentation and disclosure requirements which must be applied retrospectively for all periods presented in consolidated financial statements. We do not have significant noncontrolling interests in consolidated subsidiaries, and therefore, adoption of this standard is not expected to have a significant impact on our consolidated results of operations, financial position or cash flows.

18. Evaluation of Separation of Business

On July 31, 2008, Marathon announced that the board of directors is evaluating the separation of Marathon into two independent, publicly-traded companies, each focused on its own set of business opportunities. One entity would consist of the Exploration and Production, Integrated Gas and Oil Sands Mining businesses; and the other entity would consist of the Refining, Marketing and Transportation business.

19. Subsequent Events

On October 8, 2008, we completed the sale of our 50 percent ownership interest in Pilot Travel Centers LLC ("PTC"). Sale proceeds, before closing costs, were $625 million, with a pretax gain on the sale of approximately $125 million expected. Immediately preceding the sale, we received a $75 million redemption of our partnership interest from PTC that was accounted for as a return of investment.

On October 31, 2008, we closed the sale of our Norwegian outside-operated properties and undeveloped offshore acreage for proceeds of $320 million, before post-closing adjustments. After post-closing adjustments are finalized, the pretax gain is expected to be between $250 and $275 million. As of September 30, 2008, operating assets and liabilities with a net carrying value of $36 million were classified as held for sale, with $3 million reported in Other current assets, $94 million in Other noncurrent assets and $61 million in Deferred credits and other liabilities on the consolidated balance sheet.

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

Marathon Oil Corporation is engaged in worldwide exploration, production and marketing of liquid hydrocarbons and natural gas; mining, extraction and transportation of bitumen from oil sands deposits in Alberta, Canada, and upgrading of the bitumen for the production and marketing of synthetic crude oil and by-products; domestic refining, marketing and transportation of crude oil and petroleum products, primarily in the Midwest, upper Great Plains, Gulf Coast and southeastern regions of the United States; and worldwide marketing and transportation of products manufactured from natural gas, such as LNG and methanol, and development of other projects to link stranded natural gas resources with key demand areas. Management’s Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the Consolidated Financial Statements and Selected Notes to Consolidated Financial Statements, the Supplemental Statistics and our 2007 Annual Report on Form 10-K.

Certain sections of Management’s Discussion and Analysis of Financial Condition and Results of Operations include forward-looking statements concerning trends or events potentially affecting our business. These statements typically contain words such as “anticipates,” “believes,” “estimates,” “expects,” “targets,” “plans,” “projects,” “could,” “may,” “shou
similar words indicating that future outcomes are uncertain. In accordance with “safe harbor” provisions of the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, which could cause future outcomes to differ materially from those set forth in the forward-looking statements. For additional risk factors affecting our business, see Item 1A. Risk Factors in our 2007 Annual Report on Form 10-K.

We hold a 60 percent interest in Equatorial Guinea LNG Holdings Limited (“EGHoldings”). Effective May 1, 2007, we no longer consolidate EGHoldings. Our investment is accounted for prospectively using the equity method of accounting. Unless specifically noted, amounts presented for the Integrated Gas segment for periods prior to May 1, 2007, include amounts related to the minority interests.

Overview and Outlook

Exploration and Production (“E&P”)

Production

Net liquid hydrocarbon and natural gas sales averaged 379 and 369 thousand barrels of oil equivalent per day (“mboepd”) during the third quarter and first nine months of 2008, an increase of 2 percent and 5 percent over the same periods of 2007. Sales from the Alvheim/Vilje development offshore Norway and the Neptune development in the Gulf of Mexico more than offset declines in sales due to the deferral of certain production in the Gulf of Mexico as a result of hurricanes. Natural gas sales from the Alba field in Equatorial Guinea contributed to the increased sales in the year-to-date period.

The Alvheim development offshore Norway commenced production in June 2008. The Vilje field, which is tied back to the Alvheim floating production, storage and offloading vessel, began producing July 31, 2008. Commissioning of the Alvheim/Vilje project is continuing with a total of 10 wells currently available for production, out of 12 producing wells planned for the first phase. We have seen extended periods of production at facility capacity of 125 mboepd (75 mboepd net to Marathon) and expect further stabilization at these rates. We have a 65 percent operated interest in the Alvheim fields and a 47 percent outside-operated interest in the Vilje field.

The Neptune development in the Gulf of Mexico commenced production of liquid hydrocarbons and natural gas in early July 2008 and reached full oil capacity after 15 days of operations. The field is currently producing from 6 wells. Marathon has a 30 percent outside-operated interest in the Neptune development. The facility's design capacity is 50 thousand barrels per day ("mbpd") of oil and 50 million cubic feet per day ("mmcfd") of natural gas.

Hurricanes Gustav and Ike impacted Gulf of Mexico production in the latter part of the third quarter, resulting in 9,500 net barrels of oil equivalent per day ("boepd") being shut-in during the quarter. The Ewing Bank development resumed production in late October. The outside-operated Troika and Ursa fields remain shut-in for repairs. These fields are expected to impact fourth quarter 2008 sales by approximately 6 mboepd. We have an approximate 65 percent working interest in Ewing Bank, a 50 percent working interest in Troika and a 4 percent overriding royalty interest in Ursa.

We continue to increase sales from the Williston Basin (the Bakken shale formation) in North Dakota. We currently have 7 rigs drilling. We expect to drill 71 company-operated wells in 2008 and will have over 100 wells in the play by the end of 2008.

Exploration

During the first nine months of 2008, we announced the Portia and the Dione discoveries on Block 31 offshore Angola which were our 27th and 28th discoveries on Blocks 31 and 32. We also participated in 3 wells in our Angola exploration and appraisal program that have reached total depth, the results of which will be announced upon receipt of government and partner approval. At September 30, 2008 we were participating in one appraisal well in Block 32. On Block 31 we are currently drilling an exploratory well and plan to drill two additional exploratory wells the remainder of 2008. We hold a 10 percent outside-operated interest in Block 31 and a 30 percent outside-operated interest in Block 32.

Offshore Angola, we have received approval to proceed with the first deepwater oil development project in Block 31. The development is comprised of the Plutao, Saturno, Venus and Marte ("PSVM") fields. Key contracts are ready to be awarded and construction work is expected to begin later this year. A total of 48 production and injection wells are planned for the PSVM development.

In the third quarter of 2008, we announced a Gulf of Mexico deepwater discovery on the Gunflint prospect located on Mississippi Canyon Block 948. We own a 13 percent outside-operated interest in the block. We are also currently participating in another deepwater exploration well in the Gulf of Mexico and an appraisal well on the Stones prospect located on Walker Ridge Block 508. We hold a 25 percent outside-operated interest in Stones.

In October 2008, development of the Droshky discovery, located in the Gulf of Mexico on Green Canyon Block 244, was authorized by our board of directors. The initial Droshky discovery well and two sidetracks were drilled in 2007, followed in 2008 by a second delineation and sidetrack well. The project will consist of four development wells, which will be tied back to the nearby outside-operated Bullwinkle platform. We have secured a rig to begin drilling in 2009, and first production is targeted for 2010. Our share of sales is expected to peak at about 45 mbpd of liquid hydrocarbons and 43 mmcfd of natural gas, after royalties. We hold a 100 percent working interest in Droshky.

Also in October 2008, development of the Ozona prospect, located in the Gulf of Mexico on Garden Banks Block 515 was authorized. We have secured a rig to complete the previously drilled appraisal well and tie back to the nearby outside-operated Auger platform. First production is expected in 2011. We hold a 68 percent working interest in Ozona.

During the second quarter of 2008 we were awarded all 15 blocks bid in the Central Gulf of Mexico Lease Sale No. 206 conducted by the Minerals Management Service in the first quarter of 2008. Two blocks are 100 percent Marathon, and the remaining blocks were bid with partners, at a total cost of $121 million. Initial drilling on these leases, and those acquired at Lease Sale No. 205 in October 2007, is planned for 2009.

In Indonesia, we are the operator of a drilling rig consortium which has secured a two-year contract for a deepwater exploration drilling rig. The rig will be used for deepwater exploration activities by us and four other companies in Indonesia. The participants have the right to extend this rig commitment. Additionally, in October 2008, we were granted a 49 percent interest and operatorship in the Bone Bay Block offshore Indonesia. The Bone Bay Block is 200 miles southeast of our PasangkayuBlock, which was awarded in 2006. Current exploration plans call for the acquisition of 2D seismic starting in 2009, followed by drilling in 2011.

We ceased efforts to pursue exploration opportunities in Ukraine and closed our Kiev office in the third quarter of 2008.

Divestitures

On October 31, 2008, we closed the sale of our outside-operated interests (24 percent of Heimdal field, 47 percent of Vale field and 20 percent of Skirne field) and associated undeveloped acreage offshore Norway for proceeds of $320 million, before post-closing adjustments. When post-closing adjustments are finalized, the pretax gain on the sale is expected to be between $250 and $270 million.

During the first quarter of 2008, we transferred our interest in an exploration and production license in Sudan to the operator, and as a result, we no longer have any interests in Sudan.

The above discussions include forward-looking statements with respect to the timing and levels of future production, and anticipated future exploratory drilling activity. Some factors that could potentially affect these forward-looking statements include pricing, supply and demand for petroleum products, the amount of capital available for exploration and development, regulatory constraints, timing of commencing production from new wells, drilling rig availability, unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response, and other geological, operating and economic considerations. The foregoing forward-looking statements may be further affected by the inability to obtain or delay in obtaining necessary government and third-party approvals and permits. The disposition of interests could also be adversely affected by customary closing conditions. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Oil Sands Mining ("OSM")

Our bitumen production, before royalties, was 28 thousand barrels per day ("mbpd") in the third quarter and 25 mbpd in the first nine months of 2008. Third quarter production increased 15 percent over second quarter as a result of a greater volume of ore being mined and available to the mine processing facility. This improvement is largely a result of additional shovel excavation locations being opened in the mine enabling more consistency in ore availability.

The Athabasca Oil Sands Project ("AOSP") Expansion 1, which includes construction of mining and extraction facilities at the Jackpine mine, expansion of treatment facilities at the existing Muskeg River mine, expansion of the Scotford upgrader and development of related infrastructure, is anticipated to begin operations in 2010 or 2011. As recently announced by the operator, a final investment decision on Expansion 2 has been postponed.

In the third quarter of 2008, following achievement of project payout, the royalty rate increased to the 25 percent of net revenue post-payout rate from the one percent of gross revenue rate that had been in effect for most of the year. During the first quarter of 2008, the royalty calculation methodology for the AOSP was revised to allow for additional eligible costs to the project such that the royalty calculation adjusted retroactively to the one percent as of July 1, 2007.

The above discussion includes forward-looking statements with respect to the start of operations of AOSP Expansion 1. Factors that could be affected the project are transportation logistics, availability of materials and labor, unforeseen hazards such as weather conditions, delays in obtaining or conditions imposed by necessary government and third-party approvals and other risks customarily associated with construction projects.

Refining, Marketing and Transportation ("RM&T")

Our total refinery throughputs were 8 percent lower in the third quarter and first nine months of 2008 than in the third quarter and first nine months of 2007. Crude oil refined likewise decreased 8 percent in the same periods. Third quarter throughput declines were primarily weather-related, while planned maintenance activities at several of our refineries earlier in the year also contributed to the year-to-date throughput declines.

Our ethanol blending program in the third quarter of 2008 increased 50 percent compared to the same period of 2007. For the first nine months of 2008 we blended 36 percent more ethanol than in the same period of 2007. The future expansion or contraction of our ethanol blending program will be driven by the economics of ethanol supply and government regulations.

Third quarter 2008 Speedway SuperAmerica LLC same store gasoline sales volume decreased 12 percent when compared to the third quarter of 2007 while same store merchandise sales increased by 2 percent for the same period. Our 2007 gasoline sales included the effect of a special sales promotion.

The expansion of our Garyville refinery is 70 percent complete with an on-schedule startup expected in the fourth quarter 2009. We have identified minor cost increases for additional quantities of materials required, material and labor cost escalation and some additional costs associated with the recent hurricanes in the Gulf Coast region. We now project the expansion will cost about $3.4 billion, excluding capitalized interest, or about 5 percent more than the original estimate.

All the permits have been received for the upgrading and expansion project at the Detroit refinery. Construction started at the end of the second quarter of 2008. Due to the current market conditions, we are reevaluating the project construction schedule and expect to defer the project completion. We are currently compiling the new project schedule and cost, and expect to complete this analysis by year end 2008.

In October 2008, we completed the sale of our 50 percent ownership interest in PTC. Sale proceeds, before closing costs, were $625 million, with a pretax gain on the sale of approximately $125 million expected. Immediately preceding the sale, we received a $75 million redemption of our partnership interest from PTC that was accounted for as a return of investment.

The above discussion includes forward-looking statements with respect to the Garyville and Detroit refinery expansion projects. Factors that could affect those projects include transportation logistics, availability of materials and labor, unforeseen hazards such as weather conditions, delays in obtaining or conditions imposed by necessary government and third-party approvals, and other risks customarily associated with construction projects. These factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Integrated Gas ("IG")

We own 45 percent of Atlantic Methanol Production Company LLC ("AMPCO") and 60 percent of Equatorial Guinea LNG Holdings Limited ("EGHoldings"), both of which are accounted for under the equity method of accounting. AMPCO operates a methanol plant and EGHoldings operates a liquefied natural gas ("LNG") production facility, both located on

Bioko Island, Equatorial Guinea. Alba field dry natural gas, which remains after the condensate and liquefied petroleum gas ("LPG") are removed, is supplied to both of these facilities under long-term, fixed price contracts. We consider the prices under these contracts to be comparable to the price that could be realized from transactions with unrelated parties in this market under the same or similar circumstances, because of the location of the natural gas and limited local demand for natural gas in Equatorial Guinea.

The EGHoldings LNG production facility delivered 13 cargoes during the third quarter of 2008. Our share of LNG sales worldwide totaled 6,048 metric tonnes per day ("mtpd") for the third quarter of 2008 compared to 6,137 mtpd in the third quarter of 2007 and 6,453 mtpd in the first nine months of 2008 compared to 3,117 mtpd in the first nine months of 2007. These LNG sales volumes include both consolidated sales volumes and our share of the sales volumes of equity method investees. LNG sales from Alaska are conducted through a consolidated subsidiary. LNG and methanol sales from Equatorial Guinea are conducted through equity method investees.

Production at the LNG facility in Equatorial Guinea was curtailed in July while scheduled repairs and modifications were completed on the facility to improve the overall efficiency of the plant. The methanol plant experienced a series of planned and unplanned maintenance events, but the facility returned to full production in October 2008. Neither situation significantly impacted our financial results for the quarter.

We continue to invest in the development of new technologies to create value and supply new energy sources. In the first nine months of 2008, we recorded costs of approximately $59 million related to natural gas technology research, including completing construction and beginning the commissioning of the demonstration plant for Gas-To-FuelsTM technology.

Management's Discussion and Analysis of Results of Operations

Consolidated Results of Operations

Revenues are summarized by segment in the following table:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2008	2007	2008	2007
E&P	$ 3,873	$ 2,447	$ 10,289	$ 6,437
OSM	600	-	815	-
RM&T	18,766	14,605	52,767	40,424
IG	24	64	64	188
Segment revenues	23,263	17,116	63,935	47,049
Elimination of intersegment revenues	(347)	(231)	(1,050)	(571)
Gain (loss) on U.K. natural gas contracts	198	(123)	(37)	(111)
Total revenues	$ 23,114	$ 16,762	$ 62,848	$ 46,367
Items included in both revenues and costs and expenses:				
	$ 1,273	$ 1,352	$ 3,784	$ 3,856

Consumer excise taxes on
petroleum products and merchandise

E&P segment revenues increased $1,426 million in the third quarter and $3,852 million in the first nine months of 2008 from the comparable prior-year periods. Increased liquid hydrocarbon realizations, averaging $111.33 per barrel in the third quarter and $104.33 in the first nine months of 2008, account for the majority of the revenue increase in both periods. Additionally, sales from our new Alvheim/Vilje development in Norway increased international liquid hydrocarbon sales volumes in the third quarter. Partially offsetting the increase in liquid hydrocarbon realizations were lower natural gas sales volumes in third quarter due to more natural gas storage in Ireland and Alaska. Liquid hydrocarbon and natural gas sales volumes in the U.S. were lower in both periods primarily due to shutdowns in the third quarter for hurricanes and natural production declines in the Gulf of Mexico. Sales from the new Neptune development in the Gulf of Mexico reversed the decline trend in the third quarter, keeping liquid hydrocarbon sales volumes flat in spite of the hurricanes. For the nine-month period, international natural gas sales volumes continue to reflect an increase related to sales to the EGHoldings LNG production facility that began operations in the second quarter of 2007. This increase in fixed-price sales volumes limited the increase in our average international natural gas realizations. Our share of the income ultimately generated by the subsequent export of LNG produced by EGHoldings, as well as methanol produced by AMPCO, is reflected in our Integrated Gas segment as discussed below.

See Supplemental Statistics for information regarding net sales volumes and average realizations by geographic area.

Excluded from E&P segment revenues were gains of $198 million and losses of $123 million for the third quarters of 2008 and 2007 related to natural gas sales contracts in the U.K. that are accounted for as derivative instruments. For the first nine months of 2008 and 2007 losses of $37 million and $111 million are excluded from E&P segment revenues.

OSM segment revenues totaled $600 million in the third quarter and $815 million in the first nine months of 2008. Revenues in both periods include the impact of derivative instruments intended to mitigate price risk related to future sales of synthetic crude. Pretax gains of $255 million were included in the third quarter and pretax losses of $131 million in the first nine months of 2008. Net synthetic crude sales for the third quarter of 2008 were 32 mbpd at an average realized price of $113.42 per barrel.

See Item 3. Quantitative and Qualitative Disclosures About Market Risk for additional discussion about derivative instruments.

RM&T segment revenues increased $4,161 million in the third quarter of 2008 and $12,343 million in the first nine months of 2008 from the comparable prior-year periods. The third quarter increase primarily reflects increased refined product selling prices, slightly offset by lower refined product and liquid hydrocarbon sales volumes. For the nine -month period the increase primarily reflects increased refined product and liquid hydrocarbon selling prices, slightly offset by lower refined product and liquid hydrocarbon sales volumes.

For information on segment income, see Segment Results.

Income from equity method investments increased $100 million in the third quarter of 2008 and $341 million in the first nine months of 2008 from the comparable prior-year periods. Income from the EGHoldings LNG production facility accounts for most of the increase, as it began operations in May 2007. Forty-two cargoes of LNG were delivered during the first nine months of 2008, an average of 14 per quarter, as compared to an average of 5 per quarter in the first nine months of 2007.

Cost of revenues increased $4,041 million and $15,074 million in the third quarter and first nine months of 2008 from the comparable prior-year periods. These increases resulted primarily from increases in acquisition costs of crude oil, refinery charge and blend stocks and purchased refined products in the RM&T segment.

Exploration expenses were $109 million and $368 million in the third quarter and first nine months of 2008, including expenses related to dry wells of $24 million and $106 million. Exploration expenses were $88 million and $264 million in the third quarter and first nine months of 2007, including expenses related to dry wells of $22 million and $76 million. Other exploration expense increases in the first nine months of 2008 relate to the acquisition of seismic data in Indonesia and the evaluation of Canadian in-situ oil sands leases.

Gain on foreign currency derivative instruments in the third quarter of 2007 primarily represents unrealized gains on foreign currency derivative instruments entered to limit our exposure to changes in the Canadian dollar exchange rate related to the cash portion of the purchase price for Western.

Provision for income taxes increased $911 million and $437 million in the third quarter and first nine months of 2008 from the comparable periods of 2007 as a result of increases in income before income taxes. The geographic sources of income and related tax expense contributed to the increase in the effective income tax rates for the first nine months of 2008 when compared to the same period in 2007. The estimated 2008 effective tax rate was reduced by less than 4 percentage points by the reversal of previously recorded valuation allowances on Norwegian net operating losses.

The following is an analysis of the effective income tax rates for the first nine months of 2008 and 2007:

	Nine Months Ended September 30,	
	2008	2007
Statutory U.S. income tax rate	35 %	35 %
Effects of foreign operations, including foreign tax credits	11	8
State and local income taxes, net of federal income tax effects	1	2
Other tax effects	(1)	(1)
Effective income tax rate for continuing operations	46 %	44 %

Discontinued operations in 2007 is a sales price adjustment on the June 2006 sale of our Russian oil exploration and production businesses.

Segment Results

Segment income is summarized in the following table:

(In millions)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
E&P				
United States	$ 285	$ 147	$ 888	$ 470
International	654	332	1,563	794
E&P segment	939	479	2,451	1,264
OSM	288	-	158	-
RM&T	771	482	854	2,073
IG	65	52	266	83
Segment income	2,063	1,013	3,729	3,420
Items not allocated to segments, net of income taxes:				
Corporate and other unallocated items	(100)	3	(141)	(149)
Gain (loss) on U.K. natural gas contracts	101	(62)	(19)	(56)
Gain on foreign currency derivative instruments	-	74	-	74
Loss on early extinguishment of debt	-	(7)	-	(9)
Discontinued operations	-	-	-	8
Net income	$ 2,064	$ 1,021	$ 3,569	$ 3,288

United States E&P income increased $138 million, or 94 percent, and $418 million, or 89 percent, in the third quarter and first nine months of 2008 compared to the same periods of 2007. Pretax income increased $214 million and $665 million in the same periods. The higher pretax income in both periods is primarily a result of higher liquid hydrocarbon and natural gas realizations, partially offset by increased production taxes and higher depletion, depreciation and amortization, primarily related to new production.

International E&P income increased $322 million, or 97 percent, and $769 million, or 97 percent, in the third quarter and first nine months of 2008 compared to the same periods of 2007. Pretax income increased $693 million and $1,616 million in the same periods. The higher pretax income in both periods is primarily a result of higher liquid hydrocarbon sales volumes and realizations, partially offset by increased costs related to new production.

OSM segment income was $288 million and $ 158 million in the third quarter and first nine months of 2008. The third quarter reflects a $190 million after-tax gain, which includes a realized after-tax loss of $24 million and an unrealized after-tax gain of $214 million, on derivative instruments intended to mitigate price risk related to future sales of synthetic crude oil. For the first nine months of 2008, the after-tax derivative loss was $98 million, of which

$39 million is unrealized.

RM&T segment income increased by $289 million, or 60 percent, and decreased $1,219 million, or 59 percent, in the third quarter and first nine months of 2008 compared to the same periods of 2007. Pretax income increased $491 million and decreased $1,873 million in the same periods. The changes in RM&T pretax income in both periods are primarily the result of changes in the refining and wholesale marketing gross margin. Our refining and wholesale marketing gross margin averaged 25.19 cents per gallon in the third quarter of 2008 and 11.37 cents per gallon in the first nine months of 2008 compared to 17.17 cents per gallon and 23.17 cents per gallon in the comparable periods of 2007. The major cause of the margin increase in the third quarter was the significant drop in crude oil prices during the quarter and an increase in the average sweet/sour differentials compared to the same quarter last year. For the nine-month period, the major cause of the margin decline was the significant increase in crude oil prices in the first half of 2008, which was not reflected fully in our selling prices.

Our refining and wholesale marketing gross margin also included pretax derivative gains of $156 million and losses of $151 million in the third quarter and first nine months of 2008 compared to losses of $360 million and $472 million in the third quarter and first nine months of 2007. For a more complete explanation of our strategies to manage market risk related to commodity prices, see Quantitative and Qualitative Disclosures About Market Risk.

IG segment income increased $13 million in the third quarter of 2008 and $183 million in the first nine months of 2008 compared to the same periods of 2007 due primarily to increased income from our equity method investment in EGHoldings. The first LNG deliveries from EGHoldings' LNG production facility were made in the second quarter of 2007.

Management's Discussion and Analysis of Cash Flows and Liquidity

Cash Flows

Net cash provided by operating activities totaled $4,807 million in the first nine months of 2008, compared to $2,951 million in the first nine months of 2007. Cash provided by operating activities benefited from increased E&P segment income and the addition of the OSM segment, partially offset by a lower refining and wholesale marketing gross margin in the RM&T segment for the nine months of 2008.

Net cash used in investing activities totaled $4,800 million in the first nine months of 2008, compared to $2,609 million in the first nine months of 2007. Capital expenditures were $5,168 million compared with $2,725 million for the comparable prior-year period, with the increased spending related the Garyville refinery expansion, the Alvheim development, Gulf of Mexico exploration and development projects and the AOSP. See Supplemental Statistics for information regarding capital expenditures by segment. We received $402 million and $163 million of the funds held in trust related to the Garyville expansion in the first nine months of 2008 and 2007.

Net cash provided by financing activities was $302 million in the first nine months of 2008, compared to $333 million in the first nine months of 2007. Significant uses of cash in financing activities during both periods included stock repurchases, repayments of maturing debt and dividend payments. Financing activities for the first nine months of 2008 included the issuance of $1.0 billion in senior notes, $886 million of net commercial paper borrowings, $404 million in borrowings under the revolving credit facility and the payment and termination of the Marathon Oil Canada Corporation (previously Western Oil Sands Inc.) revolving credit facility. Financing activities for the first nine months of 2007 included the issuance of $1.5 billion in senior notes and borrowings of $578 million from the Norwegian export credit agency.

Dividends to Stockholders

On October 29, 2008, our Board of Directors declared a dividend of 24 cents per share, payable December 10, 2008, to stockholders of record at the close of business on November 19, 2008.

Derivative Instruments

See Item 3. Quantitative and Qualitative Disclosures About Market Risk for a discussion of derivative instruments and associated market risk.

Liquidity and Capital Resources

Our main sources of liquidity are cash and cash equivalents, internally generated cash flow from operations and a $3.0 billion committed revolving credit facility. Because of the alternatives available to us, we believe that our liquidity is adequate.

Subsequent to September 30, 2008, our liquidity has been further enhanced by the sales of our ownership interest in PTC and of our non-core Norwegian assets. At October 31, 2008, our cash plus availability under our revolving credit facility totaled approximately $5 billion.

We expect our 2009 capital investment and exploration budget, which we intend to finalize and announce in January 2009, to be more than 15 percent lower than 2008 expenditures, which were budgeted at $8 billion.

We believe that our access to capital resources is adequate to fund operations, including our capital spending programs, dividends, repayment of debt maturities and any amounts that ultimately may be paid in connection with contingencies.

Recently, many financial institutions (including insurance companies and banks) have come under significant financial stress, and in some cases, have become insolvent. Financial institutions participate in our revolving credit facility; provide us with business insurance coverage, cash management services, commercial letters of credit and short-term investments; and are counterparties to our commodity and foreign exchange derivative instruments. We have not experienced a significant adverse impact on our business to date. Turmoil in the capital markets could significantly increase our costs associated with borrowing.

Credit Arrangements

Our senior unsecured debt is currently rated investment grade by Standard and Poor's Corporation, Moody's Investor Services, Inc. and Fitch Ratings with ratings of BBB+, Baa1, and BBB+. Following our announcement regarding the possible separation of the upstream and downstream businesses, Moody's Investors Service placed our ratings under review for a possible downgrade. Fitch Ratings affirmed our current ratings and maintained their previously announced negative outlook. Standard & Poor's Ratings Services placed our ratings on credit watch with negative implications. Standard & Poor's removed the negative credit watch on our short-term borrowings in August 2008 when we publicly confirmed our intention to issue commercial paper in the normal course of business with all issued paper maturing and settling prior to any potential separation date.

At September 30, 2008, we had $404 million of borrowings against our revolving credit facility and we had commercial paper outstanding in the amount of $886 million under our U.S. commercial paper program that is backed by the revolving credit facility. Effective April 3, 2008, Marathon entered into an amendment to its revolving credit facility, extending the termination date on $2,625 million from May 2012 to May 2013. The remaining $375 million continues to have a termination date of May 2012. No single lender in our committed revolving credit facility holds more than 10 percent of the facility.

On March 12, 2008, we issued $1 billion aggregate principal amount of senior notes bearing interest at 5.9 percent with a maturity date of March 15, 2018. Interest on the senior notes is payable semi-annually beginning September 15, 2008.

On July 26, 2007, we filed a universal shelf registration statement with the Securities and Exchange Commission, under which we, as a well-known seasoned issuer, have the ability to issue and sell an indeterminate amount of various types of debt and equity securities.

Our cash-adjusted debt-to-capital ratio (total debt-minus-cash to total debt-plus-equity-minus-cash) was 23 percent at September 30, 2008, compared to 22 percent at year-end 2007 as shown below. This includes $485 million of debt that is serviced by United States Steel Corporation ("United States Steel").

(In millions)		September 30, 2008		December 31, 2007
Short-term debt	$	1,290	$	-
Long-term debt due within one year		88		1,131
Long-term debt		7,074		6,084
Total debt	$	8,452	$	7,215
Cash	$	1,479	$	1,199
Trusteed funds from revenue bonds	$	363	$	744
Equity	$	21,927	$	19,223
Calculation:				
Total debt	$	8,452	$	7,215

Minus cash		1,479		1,199
Minus trusteed funds from revenue bonds		363		744
Total debt minus cash	$	6,610	$	5,272
Total debt		8,452		7,215
Plus equity		21,927		19,223
Minus cash		1,479		1,199
Minus trusteed funds from revenue bonds		363		744
Total debt plus equity minus cash	$	28,537	$	24,495
Cash-adjusted debt-to-capital ratio		23%		22%

Our opinions concerning liquidity and our ability to avail ourselves in the future of the financing options mentioned in the above forward-looking statements are based on currently available information. If this information proves to be inaccurate, future availability of financing may be adversely affected. Estimates may differ from actual results. Factors that affect the availability of financing include our performance (as measured by various factors including cash provided from operating activities), the state of worldwide debt and equity markets, investor perceptions and expectations of past and future performance, the global financial climate, and, in particular, with respect to borrowings, the levels of our outstanding debt and credit ratings by rating agencies.

Stock Repurchase Program

Since January 2006, our Board of Directors has authorized a common share repurchase program totaling $5 billion. As of September 30, 2008, we had repurchased 66 million common shares at a cost of $2,922 million. 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.

The forward-looking statements about our common stock repurchase program are based on current expectations, estimates and projections and are not guarantees of future performance. Actual results may differ materially from these expectations, estimates and projections and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. Some factors that could cause actual results to differ materially are changes in prices of and demand for crude oil, natural gas and refined products, actions of competitors, disruptions or interruptions of our production, refining and mining operations due to unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response thereto, and other operating and economic considerations.

Contractual Cash Obligations

As of September 30, 2008, our consolidated contractual cash obligations have decreased by $3,134 million from December 31, 2007. Our purchase obligations under crude oil, refinery feedstock, refined product and ethanol contracts, which are primarily short term, decreased $4,071 million primarily related to decreased crude oil volumes, partially offset by higher liquefied petroleum gas volumes when comparing the first nine months of 2008 to December 31, 2007. Short and long-term debt increased by $1,257 million primarily due to the issuance of commercial paper and borrowings under our revolving credit facility. There have been no other significant changes to our obligations to make future payments under existing contracts subsequent to December 31, 2007. The portion of our obligations to make future payments under existing contracts that have been assumed by United States Steel has not changed significantly subsequent to December 31, 2007.

Evaluation of Separation of Business

On July 31, 2008, Marathon announced that the board of directors is evaluating the separation of Marathon into two independent, publicly-traded companies, each focused on its own set of business opportunities. One entity would consist of the Exploration and Production, Integrated Gas and Oil Sands Mining businesses; and the other entity would consist of the Refining, Marketing and Transportation business. Results of this evaluation and a decision by the board of directors are anticipated in the fourth quarter of 2008.

The above discussion includes forward-looking statements with respect to the evaluation of separating Marathon into two distinct businesses. Some factors that could potentially affect these forward-looking statements include board approval, future financial condition and operating results, and economic, business, competitive and/or regulatory factors affecting our business. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Critical Accounting Estimates

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

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

There have been no changes to our critical accounting estimates subsequent to December 31, 2007, except those related to fair value estimates resulting from the adoption of SFAS No. 157 as discussed below.

Fair Value Estimates

On January 1, 2008, we adopted SFAS No. 157 for those financial assets and liabilities recognized or disclosed at fair value in the consolidated financial statements on a recurring basis. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. It does not require us to make any new fair value measurements, but rather establishes a fair value hierarchy that prioritizes the inputs to the valuation techniques used to measure fair value. Level 1 inputs are given the highest priority in the fair value hierarchy, as they represent observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date, while Level 3 inputs are given the lowest priority, as they represent unobservable inputs that are not corroborated by market data. Valuation techniques that maximize the use of observable inputs are favored.

FSP FAS 157-2, “Effective Date of FASB Statement No. 157,” deferred the effective date of SFAS No. 157 for one year for certain nonfinancial assets and nonfinancial liabilities, which for us includes impairments of goodwill, intangible assets and other long-lived assets, and initial measurement of asset retirement obligations, asset exchanges, business combinations and partial sales of proved properties.

For Marathon, the primary impact from the adoption of SFAS No. 157 at January 1, 2008, related to the fair value measurement of derivative instruments. Additional information about derivatives and their valuation may be found in Item 3. Quantitative and Qualitative Disclosures About Market Risk.

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, production processes and whether it is also engaged in the petrochemical business or the marine transportation of crude oil, refined products and feedstocks.

Legislation and regulations pertaining to climate change and greenhouse gas emissions have the potential to impact us. The Energy Independence and Security Act and California laws contain provisions related to greenhouse gas emissions. Other climate change legislation and regulations both in the United States and abroad are in various stages of development. Our industry, and other businesses throughout the United States, is also awaiting the U.S. Environmental Protection Agency’s (“EPA”) actions upon the remand of the U.S. Supreme Court decision in Massachusetts v. USEPA, which could have impacts on a number of air emissions permitting and environmental regulatory programs. In July of 2008, the EPA issued an Advanced Notice of Proposed Rulemaking (“ANPR”) to address the Supreme Court decision and to seek public input through November 2008 on potential actions it may take to regulate greenhouse gas emissions. Action by EPA on the ANPR is not expected until 2009. Emissions arise from our operations, including the refining of crude oil and the transportation of crude oil and refined products. Although there may be adverse financial impact (including compliance costs, potential permitting delays and potential reduced demand for certain refined products) associated with any legislation, regulation, EPA or other action, the extent and magnitude of that impact cannot be reliably or accurately estimated due to the fact that requirements have only recently been adopted and the present uncertainty regarding the additional measures and how they will be implemented. Litigation has also been brought against emitters of greenhouse gas emissions but Marathon has not been named in those cases. As part of our commitment to environmental stewardship, we estimate and publicly report greenhouse gas emissions from our operations. We are working to continuously improve the accuracy and completeness of these estimates. In addition, we continuously strive to improve operational and energy efficiencies through resource and energy conservation where practicable and cost effective.

The EPA is in the process of implementing regulations to address current National Ambient Air Quality Standards ("NAAQS") for fine particulate emissions and ozone. In connection with these standards, the EPA will designate certain areas as "nonattainment," meaning that the air quality in such areas does not meet the NAAQS. To address these nonattainment areas, the EPA proposed a rule in 2004 called the Interstate Air Quality Rule ("IAQR") that would require significant emissions reductions in numerous states. The final rule, promulgated in 2005, was renamed the Clean Air Interstate Rule ("CAIR"). While the EPA expected that states would meet their CAIR obligations by requiring emissions reductions from electric generating units, states were to have the final say on what sources they regulate to meet attainment criteria. Significant uncertainty in the final requirements of this rule comes from litigation (State of North Carolina, et al v. EPA). On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated the CAIR in its entirety and remanded it to EPA to promulgate a rule consistent with the Court's opinion. The CAIR will be significantly altered, and it could result in changes in emissions control strategies. Our refinery operations are located in affected states and some of these states may choose to propose more stringent fuels requirements to meet the

CAIR. Also, in 2007, the EPA proposed a revised ozone standard. This revised ozone standard was promulgated in March of 2008, and the EPA is starting the multi-year process to develop the implementing rules required by the Clean Air Act. We cannot reasonably estimate the final financial impact of the state actions to implement the CAIR until the EPA has issued a revised rule and states have taken further action to implement that rule. We also cannot reasonably estimate the final financial impact of the revised ozone standard until the implementing rules are established and judicial challenges over the revised ozone standard are resolved.

We previously reported that we have not finalized our strategy or cost estimate to comply with Mobile Source Air Toxics II regulations relating to benzene, but the cost estimate may be approximately $1 billion over a three-year period beginning in 2008, with $31 million spent through September 30, 2008. This cost estimate is a forward-looking statement and is subject to change as further work is completed in 2008 and 2009.

There have been no other significant changes to our environmental matters subsequent to December 31, 2007.

Other Contingencies

We are the subject of, or a party to, a number of pending or threatened legal actions, contingencies and commitments involving a variety of matters, including laws and regulations relating to the environment. The ultimate resolution of these contingencies could, individually or in the aggregate, be material to us. However, we believe that we will remain a viable and competitive enterprise even though it is possible that these contingencies could be resolved unfavorably to us. See Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources.

Accounting Standards Not Yet Adopted

In June 2008, the FASB issued FSP on EITF 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities" ("FSP EITF 03-6-1") which provides that unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and, therefore, need to be included in the earnings allocation in computing earnings per share ("EPS") under the two-class method. FSP EITF 03-6-1 is effective January 1, 2009 and all prior-period EPS data (including any amounts related to interim periods, summaries of earnings and selected financial data) will be adjusted retrospectively to conform to its provisions. Early application of FSP EITF 03-6-1 is not permitted. Although restricted stock awards meet this definition of participating securities, we do not expect application of FSP EITF 03-6-1 to have a significant impact on our reported EPS.

In April 2008, the FASB issued FSP on FAS 142-3 ("FSP FAS 142-3") which amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under SFAS No. 142, "Goodwill and Other Intangible Assets." The intent of this FSP is to improve the consistency between the useful life of a recognized intangible asset and the period of expected cash flows used to measure the fair value of the asset. FSP FAS 142-3 is effective on January 1, 2009, early adoption is prohibited. The provisions of FSP FAS 142-3 are to be applied prospectively to intangible assets acquired after the effective date, except for the disclosure requirements which must be applied prospectively to all intangible assets recognized as of, and subsequent to, the effective date. Since this standard will be applied prospectively, adoption is not expected to have a significant impact on our consolidated results of operations, financial position or cash flows.

In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133." This statement expands the disclosure requirements for derivative instruments to provide information regarding (i) how and why an entity uses derivative instruments, (ii) how derivative instruments and related hedged items are accounted for under SFAS No. 133 and its related interpretations and (iii) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. To meet these objectives, the statement requires qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts and gains and losses on derivative instruments and disclosures about credit-risk-related contingent features in derivative agreements. This standard is effective January 1, 2009. The statement encourages but does not require disclosures for earlier periods presented for comparative purposes at initial adoption. We will expand our disclosures in accordance with SFAS No. 161 beginning in the first quarter of 2009; however, the adoption of this standard is not expected to have a significant impact on our consolidated results of operations, financial position or cash flows.

In December 2007, the FASB issued SFAS No. 141 (Revised 2007), "Business Combinations" ("SFAS No. 141 (R)"). This statement significantly changes the accounting for business combinations. Under SFAS No.141(R), an acquiring entity will be required to recognize all the assets acquired, liabilities assumed and any non-controlling interest in the acquiree at their acquisition-date fair value with limited exceptions. The statement expands the definition of a business and is expected to be applicable to more transactions than the previous business combinations standard. The statement also changes the accounting treatment for changes in control, step acquisitions, transaction costs, acquired contingent liabilities, in-process research and development, restructuring costs, changes in deferred tax asset valuation allowances as a result of a business combination and changes in income tax uncertainties after the acquisition date. Accounting for changes in valuation allowances for acquired deferred tax assets and the resolution of uncertain tax positions for prior business combinations will impact tax expense instead of impacting recorded goodwill. Additional disclosures are also required. SFAS No. 141(R) is effective on January 1, 2009 for all new business combinations. We are currently evaluating the provisions of this statement.

Also in December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements - An Amendment of ARB No. 51." This statement establishes new accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. Specifically, this statement clarifies that a noncontrolling interest in a subsidiary (sometimes called a minority interest) is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements, but separate from the parent's equity. It requires that the amount of consolidated net income attributable to the noncontrolling interest be clearly identified and presented on the face of the consolidated income statement. SFAS No. 160 clarifies that changes in a parent's ownership interest in a subsidiary that do not result in deconsolidation are equity transactions if the parent retains its controlling financial interest. In addition, this statement requires that a parent recognize a gain or loss in net income when a subsidiary is deconsolidated, based on the fair value of the noncontrolling equity investment on the deconsolidation date. Additional disclosures are required that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS No. 160 is effective January 1, 2009 and early adoption is prohibited. The statement must be applied prospectively, except for the presentation and disclosure requirements which must be applied retrospectively for all periods presented in consolidated financial statements. We do not have significant noncontrolling interests in consolidated subsidiaries, and therefore, adoption of this standard is not expected to have a significant impact on our consolidated results of operations, financial position or cash flows.

ITEM 3. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risks related to the volatility of crude oil, natural gas and refined product prices. We employ various strategies, including the use of commodity derivative instruments, to manage the risks related to these price fluctuations. We are also exposed to market risks related to changes in interest rates and foreign currency exchange rates. We employ various strategies, including the use of financial derivative instruments, to manage the risks related to these fluctuations. We are at risk for changes in the fair value of all of our derivative instruments; however, such risk should be mitigated by price or rate changes related to the underlying commodity or financial transaction.

We believe that our use of derivative instruments, along with our risk assessment procedures and internal controls, does not expose us to material adverse consequences. While the use of derivative instruments could materially affect our results of operations in particular quarterly or annual periods, we believe that the use of these instruments will not have a material adverse effect on our financial position or liquidity.

Commodity Price Risk

Our strategy is to obtain competitive prices for our products and allow operating results to reflect market price movements dictated by supply and demand. We use a variety of commodity derivative instruments, including futures, forwards, swaps and combinations of options, as part of an overall program to manage commodity price risk in our different businesses. We also may utilize the market knowledge gained from these activities to do a limited amount of trading not directly related to our physical transactions.

Our E&P segment primarily uses commodity derivative instruments to mitigate the natural gas price risk during the time that the natural gas is held in storage before it is sold or on natural gas that is purchased to be marketed with our own natural gas production. We also may use commodity derivative instruments selectively to protect against price decreases on portions of our future sales of liquid hydrocarbons or natural gas when it is deemed advantageous to do so. The majority of these derivatives are measured at fair value with a market approach using broker quotes or third-party pricing services, which have been corroborated with data from active markets, making them a Level 2 in the fair value hierarchy described by SFAS No. 157.

Unrealized gains and losses on certain natural gas contracts in the United Kingdom that are accounted for as derivative instruments are excluded from E&P segment income. These contracts originated in the early 1990s and expire in September 2009. The contract prices are reset annually in October based on the previous twelve-month changes in a basket of energy and other indices. Consequently, the prices under these contracts do not track forward natural gas prices. The reported fair value of the U.K. natural gas contracts is measured with an income approach by applying the difference between the contract price and the U.K. forward natural gas strip price to the expected sales volumes for the shorter of the remaining contract term or 18 months. Such an internally generated model is classified as Level 3 in the fair value hierarchy described by SFAS No. 157.

Our OSM segment may use commodity derivative instruments to protect against price decreases on portions of our future sales of synthetic crude oil when it is deemed advantageous to do so. The reported fair value of these crude oil options, which expire December 2009, is measured using a Black-Scholes option pricing model, which is an income approach that utilizes prices from the active commodity market and market volatility calculated by a third-party service. Because a third-party service is used, and their inputs represent unobservable market data, these are classified as Level 3 in the fair value hierarchy.

Our RM&T segment primarily uses commodity derivative instruments on a selective basis to mitigate crude oil price risk during the time that crude oil inventories are held before they are actually refined into salable petroleum products. We also use derivative instruments in our RM&T segment to manage price risk related to refined petroleum products, feedstocks used in the refining process and ethanol blended with refined petroleum products. We use commodity derivative instruments to mitigate crude oil price risk between the time that crude oil purchases are priced and when they are actually refined into salable petroleum products, but we have decreased our use of derivatives in this manner as described further below. The majority of these derivatives are exchange-traded contracts for crude oil, natural gas, refined products and ethanol measured at fair value with a market approach using the close-of-day settlement prices for the market making them a Level 1 in the fair value hierarchy. When broker accounts are covered by master netting agreements the broker deposits are netted against the value to arrive at the fair values of Level 1 and Level 2 commodity derivatives.

Generally, commodity derivative instruments used in our E&P segment qualify for hedge accounting. As a result, we do not recognize in net income any changes in the fair value of those derivative instruments until the underlying physical transaction occurs. We have not qualified commodity derivative instruments used in our OSM or RM&T segments for hedge accounting. As a result, we recognize in net income all changes in the fair value of derivative instruments used in those operations.

Open Commodity Derivative Positions as of September 30, 2008 and Sensitivity Analysis

At September 30, 2008, our E&P segment held open derivative contracts to mitigate the price risk on natural gas held in storage or purchased to be marketed with our own natural gas production in amounts that were in line with normal levels of activity. At September 30, 2008, we had no open derivative contracts related to our future sales of liquid hydrocarbons and natural gas and therefore remained substantially exposed to market prices of these commodities.

Our OSM segment holds options indexed to West Texas Intermediate crude oil, covering a three-year period ending December 31, 2009. The premiums for the put options were partially offset by the sale of call options for the same period, resulting in a net premium liability. Payment of the net premium liability is deferred until the settlement of the option contracts. We have entered no new derivatives since we acquired the OSM business.

At September 30, 2008, the number of open derivative contracts held by our RM&T segment was lower than in previous periods. Starting in the second quarter of 2008, we decreased our use of derivatives to mitigate crude oil price risk between the time that domestic spot crude oil purchases are priced and when they are actually refined into salable petroleum products. Instead, we are addressing this price risk through other means, including changes in contractual terms and crude oil acquisition practices.

Additionally, in previous periods, certain contracts in our RM&T segment for the purchase or sale of commodities were not qualified or designated as normal purchase or normal sales under generally accepted accounting principles and therefore were accounted for as derivative instruments. During the second quarter of 2008, as we decreased our use of derivatives, we began to designate such contracts for the normal purchase and normal sale exclusion as we entered into new arrangements. We intend to continue to designate new contracts as normal purchase or normal sales contracts.

Sensitivity analysis of the incremental effects on income from operations ("IFO") of hypothetical 10 percent and 25 percent changes in commodity prices for open commodity derivative instruments as of September 30, 2008, is provided in the following table. The direction of the price change used in calculating the sensitivity amount for each commodity reflects that which would result in the largest incremental decrease in IFO when applied to the commodity derivative instruments used to hedge that commodity.

	Incremental Decrease in IFO Assuming a Hypothetical Price Change of (a)	
(In millions)	10%	25%
Commodity Derivative Instruments: (b)		
Crude oil	$ 98 (c)	$ 250 (c)
Natural gas	73 (c)	157 (c)
Refined products	13 (d)	32 (d)

(a) We remain at risk for possible changes in the market value of commodity derivative instruments; however, such risk should be mitigated by price changes in the underlying physical commodity. Effects of these offsets are not reflected in the sensitivity analysis. Amounts reflect hypothetical 10 percent and 25 percent changes in closing commodity prices for each open contract position at September 30, 2008. Included in the natural gas impacts above are $73 million and $158 million for hypothetical price changes of 10 percent and 25 percent related to the U.K. natural gas contracts accounted for as derivative instruments. We evaluate our portfolio of commodity derivative instruments on an ongoing basis and add or revise strategies in anticipation of changes in market conditions and in risk profiles. We are also exposed to credit risk in the event of nonperformance by counterparties. The creditworthiness of counterparties is reviewed continuously and master netting agreements are used when practical. Changes to the portfolio after September 30, 2008, would cause future IFO effects to differ from those presented above.

(b) The number of net open contracts for the E&P segment varied throughout the third quarter of 2008, from a low of 21 contracts on July 1, 2008, to a high of 381 contracts on July 27, 2008, and averaged 211 for the quarter. The number of net open contracts for the RM&T segment varied throughout the third quarter of 2008, from a low of 151 contracts on September 11, 2008, to a high of 7,475 contracts on August 13, 2008, and averaged 3,662 for the quarter. The number of net open contracts for the OSM segment varied throughout the third quarter of 2008, from a low of 15,995 contracts on September 30, 2008 to a high of 18,130 contracts on July 1, 2008 and averaged 17,068 for the quarter. The commodity derivative instruments used and positions taken will vary and, because of these variations in the composition of the portfolio over time, the number of open contracts by itself cannot be used to predict future income effects.

(c) Price increase.

(d) Price decrease.

Interest Rate Risk

We are impacted by interest rate fluctuations which affect the fair value of certain financial instruments. We manage our exposure to interest rate movements by utilizing financial derivative instruments. The primary objective of this program is to reduce our overall cost of borrowing by managing the mix of fixed and floating interest rate debt in our portfolio. As of September 30, 2008, we had multiple interest rate swap agreements with a total notional amount of $450 million, designated as a fair value hedge, which effectively resulted in an exchange of existing obligations to pay fixed interest rates for obligations to pay floating rates. The weighted average floating rate on these swap agreements is LIBOR plus 2.060 percent.

Sensitivity analysis of the projected incremental effect of a hypothetical 10 percent change in interest rates on financial assets and liabilities as of September 30, 2008, is provided in the following table.

(In millions)	Fair Value	Incremental Change in Fair Value
Financial assets (liabilities): (a)		
Receivable from United States Steel	$ 469	$ 13 (c)
Interest rate swap agreements	$ 5 (b)	$ 5 (c)
Long-term debt, including amounts due within one year	$ (6,263) (b)	$ (366) (c)

(a) Fair values of cash and cash equivalents, receivables, notes payable, 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.

(c) For receivables from United States Steel and long-term debt, this assumes a 10 percent decrease in the weighted average yield-to-maturity of our receivables and long-term debt at September 30, 2008. For interest rate swap agreements, this assumes a 10 percent decrease in the effective swap rate at September 30, 2008.

At September 30, 2008, our portfolio of long-term debt was substantially comprised of fixed rate instruments. Therefore, the fair value of the portfolio is relatively sensitive to interest rate fluctuations. Our sensitivity to interest rate declines and corresponding increases in the fair value of our debt portfolio unfavorably affects our results of operations and cash flows only when we elect to repurchase or otherwise retire fixed-rate debt at prices above carrying value.

Foreign Currency Exchange Rate Risk

We manage our exposure to foreign currency exchange rates by utilizing forward and option contracts. The primary objective of this program is to reduce our exposure to movements in foreign currency exchange rates by locking in such rates. The following tables summarize our derivative foreign currency derivative instruments as of September 30, 2008.

(In millions)	Period	Notional Amount	Average Forward Rate (a)	Fair Value (b)
Foreign Currency Forwards:				
Dollar (Canada)	November 2008 - February 2010	$ 375	1.036 (d)	$ (10)
Euro	November 2008 - January 2009	$ 25	1.413 (d)	$ -

Kroner (Norway)	October 2008 - October 2009	$ 36	6.085 (c)	$ 1

(a) Rates shown are weighted average forward rates for the period.

(b) Fair value was based on market rates.

(c) U.S. dollar to foreign currency.

(d) Foreign currency to U.S. dollar.

(In millions)	Period	Notional Amount	Weighted Average Exercise Price (a)	Fair Value (b)
Foreign Currency Options:				
Dollar (Canada)	October 2008 - December 2008	100	1.015 (c)	1

(a) Rates shown are weighted average exercise prices for the period.

(b) Fair value was based on market rates.

(c) U.S. dollar to foreign currency.

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The aggregate cash flow effect on foreign currency contracts of a hypothetical 10 percent change to exchange rates at September 30, 2008, would be approximately $39 million.

Safe Harbor

These quantitative and qualitative disclosures about market risk include forward-looking statements with respect to management's opinion about risks associated with the use of derivative instruments. These statements are based on certain assumptions with respect to market prices and industry supply of and demand for crude oil, natural gas, refined products and other feedstocks. If these assumptions prove to be inaccurate, future outcomes with respect to our use of derivative instruments may differ materially from those discussed in the forward-looking statements.

Item 4. Controls and Procedures

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) was carried out under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. As of the end of the period covered by this report based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective. During the quarter ended September 30, 2008, 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.

We review and modify our financial and operational controls on an ongoing basis to ensure that those controls are adequate to address changes in our business as it evolves. We believe that our existing financial and operational controls and procedures are adequate.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions, except as noted)	2008	2007	2008	2007
Segment Income				
Exploration and Production				
United States	$ 285	$ 147	$ 888	$ 470
International	654	332	1,563	794
E&P segment	939	479	2,451	1,264
Oil Sands Mining	288	-	158	-
Refining, Marketing and Transportation	771	482	854	2,073
Integrated Gas	65	52	266	83
Segment income	2,063	1,013	3,729	3,420
Items not allocated to segments, net of income taxes:				
Corporate and other unallocated items	(100)	3	(141)	(149)
Gain (loss) on U.K. natural gas contracts	101	(62)	(19)	(56)
Gain on foreign currency derivative instruments	-	74	-	74
Loss on early extinguishment of debt	-	(7)	-	(9)
Discontinued operations	-	-	-	8
Net income	$ 2,064	$ 1,021	$ 3,569	$ 3,288
Capital Expenditures				
Exploration and Production	$ 738	$ 582	$ 2,387	$ 1,623
Oil Sands Mining	271	-	781	-
Refining, Marketing and Transportation	765	430	1,978	981
Integrated Gas (a)	3	2	4	93
Corporate	9	12	18	28
Total	$ 1,786	$ 1,026	$ 5,168	$ 2,725
Exploration Expenses				
United States	$ 68	$ 53	$ 173	$ 137
International	41	35	195	127
Total	$ 109	$ 88	$ 368	$ 264
E&P Operating Statistics				
Net Liquid Hydrocarbon Sales (mbpd) (b)				
United States	63	63	63	66
Europe	66	33	43	33
Africa	95	103	93	100
Total International	161	136	136	133
Worldwide	224	199	199	199
Net Natural Gas Sales (mmcfd) (b)(c)				
United States	426	464	446	478
Europe	156	195	195	206
Africa	346	372	379	221
Total International	502	567	574	427
Worldwide	928	1,031	1,020	905

Total Worldwide Sales (mboepd)	379	371	369	350

(a) Through April 2007, includes EGHoldings at 100 percent. Effective May 1, 2007, we no longer consolidate EGHoldings and its investment in EGHoldings is accounted for prospectively using the equity method of accounting; therefore, EGHoldings' capital expenditures subsequent to April 2007 are not included in our capital expenditures.

(b) Amounts reflect sales after royalties, except for Ireland where amounts are before royalties.

(c) Includes natural gas acquired for injection and subsequent resale of 2 mmcfd and 51 mmcfd in the third quarters of 2008 and 2007, and 21 mmcfd and 49 mmcfd for the first nine months of 2008 and 2007.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

(In millions, except as noted)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
E&P Operating Statistics (continued)				
Average Realizations (d)				
Liquid Hydrocarbons (per bbl)				
United States	$ 106.81	$ 63.53	$ 100.27	$ 55.83
Europe	118.52	73.19	115.15	63.80
Africa	109.36	69.48	102.11	60.57
Total International	113.10	70.37	106.21	61.37
Worldwide	$ 111.33	$ 68.21	$ 104.33	$ 59.54
Natural Gas (per mcf)				
United States	$ 7.70	$ 5.14	$ 7.70	$ 5.74
Europe	8.85	6.47	8.10	5.95
Africa(e)	0.25	0.25	0.25	0.25
Total International	2.92	2.38	2.91	3.01
Worldwide	$ 5.11	$ 3.63	$ 5.00	$ 4.45
OSM Operating Statistics				
Net Bitumen Production (mbpd) (f)	28	-	25	-
Net Synthetic Crude Sales (mbpd) (f)	32	-	31	-
Synthetic Crude Average Realization (per bbl)	$ 113.42	$ -	$ 106.37	$ -
RM&T Operating Statistics				
Refinery Runs (mbpd)				
Crude oil refined	955	1,042	941	1,028
Other charge and blend stocks	189	199	201	211
Total	1,144	1,241	1,142	1,239
Refined Product Yields (mbpd)				
Gasoline	586	646	598	649
Distillates	358	358	336	352
Propane	21	24	22	24
Feedstocks and special products	95	111	104	118
Heavy fuel oil	20	27	24	25
Asphalt	79	93	75	87
Total	1,159	1,259	1,159	1,255
Refined Products Sales Volumes (mbpd) (g)	1,357	1,440	1,335	1,403
Refining and Wholesale Marketing Gross				

Margin (per gallon) (h)	$ 0.2519	$ 0.1717	$ 0.1137	$ 0.2317
Speedway SuperAmerica				
Retail outlets	1,620	1,637	-	-
Gasoline and distillate sales (millions of gallons)	796	892	2,376	2,520
Gasoline and distillate gross margin (per gallon)	$ 0.1690	$ 0.1103	$ 0.1235	$ 0.1115
Merchandise sales	$ 764	$ 752	$ 2,133	$ 2,110
Merchandise gross margin	$ 197	$ 191	$ 541	$ 533
IG Operating Statistics				
Net Sales (mtpd) (i)				
LNG	6,048	6,137	6,453	3,117
Methanol	757	1,421	1,024	1,285

(d) Excludes gains and losses on traditional derivative instruments and the unrealized effects U.K. natural gas contracts that are accounted for as derivatives.

(e) Primarily represents a fixed price under long-term contracts with Alba Plant LLC, AMPCO and EGHoldings, equity method investees. We include our share of Alba Plant LLC's income in our E&P segment and we include our share of AMPCO's and EGHoldings' income in our Integrated Gas segment.

(f) Amounts are before royalties.

(g) Total average daily volumes of all refined product sales to wholesale, branded and retail (SSA) customers.

(h) Sales revenue less cost of refinery inputs, purchased products and manufacturing expenses, including depreciation.

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

Part II – OTHER INFORMATION

Item 1. Legal Proceedings

MTBE Litigation

We, along with some other defendants with refinery operations, recently settled a number of lawsuits alleging methyl tertiary butyl ether ("MTBE") contamination of water supply wells. We were a defendant in 40 of the cases settled. Our share of the cash portion of the settlement was paid in October 2008 and did not significantly impact our consolidated results of operations, financial position or cash flows. Under the settlement, the settling defendants, including our company, are responsible for addressing future MTBE contamination in certain water supply wells. We do not expect that our share of liability for any such future obligations under the settlement to significantly impact our consolidated results of operations, financial position or cash flows.

We, along with other companies with refinery operations, remain a defendant in 21 cases arising in three states alleging damages for MTBE contamination. Like the cases that were recently settled, the remaining cases, have been consolidated in a multi-district litigation ("MDL") in the Southern District of New York for pretrial proceedings. Twenty of the remaining cases allege damages to water supply wells, similar to the damages claimed in the settled cases. In the other remaining case, the State of New Jersey is seeking natural resources damages allegedly resulting from contamination of groundwater by MTBE. This is the only MTBE contamination case in which natural resources damages are sought. We do not expect that our share of liability, if any, for the remaining cases to significantly impact our consolidated results of operations, financial position or cash flows.

Product Contamination Litigation

A lawsuit was filed in the United States District Court for the Southern District of West Virginia which alleges that the Catlettsburg, Kentucky, refinery distributed contaminated gasoline to wholesalers and retailers for a period prior to August, 2003, causing permanent damage to storage tanks, dispensers and related equipment, resulting in lost profits, business disruption and personal and real property damages. Following the incident, we conducted remediation operations at affected facilities, and we have denied that any permanent damages resulted from the incident. Class action certification was granted in August 2007. We have entered into a tentative settlement agreement in this case, but both a notice to the class members and approval by the court after a fairness hearing are required before the settlement can be finalized. The settlement is not expected to significantly impact our consolidated results of operations, financial position or cash flows.

Environmental Proceedings

The U.S. Occupational Safety and Health Administration ("OSHA") announced a National Emphasis Program pursuant to which it plans to inspect domestic petroleum refinery locations. The inspections began in 2007 and have focused on compliance with the OSHA Process Safety Management requirements. An inspection was conducted by U.S. OSHA in late 2007 at the Canton, Ohio refinery. That inspection resulted in an informal settlement agreement with OSHA in December 2007 under which we paid a penalty of $321,500 and agreed to various abatement measures. U.S. OSHA also conducted a one-week inspection of our Robinson, Illinois, refinery in the first quarter of 2008. An inspection of the Detroit, Michigan, refinery was conducted in the fall of 2008 as a prelude to an inspection of the refinery for OSHA VPP status. U.S. OSHA and Kentucky OSHA have conducted extensive inspections of our Texas City, Texas, and Catlettsburg, Kentucky, refineries, respectively, in the summer and fall of 2008. No enforcement has been taken with regard to the 2008 Robinson and Detroit inspections and one citation with no penalty was assessed at Catlettsburg. Enforcement is expected in the fourth quarter of 2008 related to the Texas City inspection and the outcome is not expected to be significant. U.S. OSHA or state OSHAs may conduct inspections of our other refineries during 2008 or 2009 and enforcement actions may result from these inspections.

Item 1A. Risk Factors

We are subject to various risks and uncertainties in the course of our business. See the discussion of such risks and uncertainties under Item 1A. Risk Factors in our 2007 Annual Report on Form 10-K. There have been no material changes from the risk factors previously disclosed in that Form 10-K.

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

	(a)	(b)	(c)	(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 (d)	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (d)
07/01/08 – 07/31/08	1,107,468	$46.67	1,092,100	$2,131,137,229
08/01/08 – 08/31/08	1,064,237	$45.23	1,062,700	$2,083,081,024
09/01/08 – 09/30/08	210,395 (c)	$44.94	171,000	$2,080,366,711
Total	2,382,100	$45.87	2,325,800	

(a) 18,831 shares of restricted stock were delivered by employees to Marathon, upon vesting, to satisfy tax withholding requirements.

(b) Under the terms of the transaction whereby we acquired the minority interest in Marathon Petroleum Company and other businesses from Ashland, Marathon paid Ashland shareholders cash in lieu of issuing fractional shares of our common stock to which such holders would otherwise be entitled. We acquired 18 shares due to acquisition share exchanges and Ashland share transfers pending at the closing of the transaction.

(c) 37,451 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.

(d) We announced a share repurchase program in January 2006, and amended it several times in 2007 for a total authorized program of $5 billion. As of September 30, 2008, 66 million split-adjusted common shares had been acquired at a cost of $2,922 million, which includes transaction fees and commissions that are not reported in the table above.

Item 6. Exhibits

3.1 By-laws of Marathon Oil Corporation, effective October 29, 2008 (incorporated by reference to Exhibit 3.1 of the Form 8-K filed November 4, 2008)

10.1 Marathon Oil Corporation 1990 Stock Plan, as Amended and Restated Effective January 1, 2002

10.2 First Amendment to Marathon Oil Corporation 1990 Stock Plan (as Amended and Restated Effective January 1, 2002)

12.1 Computation of Ratio of Earnings to Fixed Charges

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

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

32.1 Certification of President and Chief Executive Officer pursuant to 18 U.S.C. Section 1350

32.2 Certification of Executive Vice President and Chief Financial Officer pursuant to 18 U.S.C. Section 1350

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

November 7, 2008	MARATHON OIL CORPORATION
	By: Michael K. Stewart Michael K. Stewart Vice President, Accounting and Controller