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

FORM 10-Q

(Mark One)

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the Quarterly Period Ended June 30, 2009

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 X No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of

Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes 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 X		Accelerated filer
Non-accelerated filer	(Do not check if a smaller reporting company)	Smaller reporting company

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

There were 707,726,372 shares of Marathon Oil Corporation common stock outstanding as of July 31, 2009.

MARATHON OIL CORPORATION

Form 10-Q

Quarter Ended June 30, 2009

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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).

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Part I - Financial Information

Item 1. Financial Statements

MARATHON OIL CORPORATION
Consolidated Statements of Income (Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions, except per share data)	2009	2008	2009	2008
Revenues and other income:				
Sales and other operating revenues (including consumer excise taxes)	$ 13,059	$ 21,203	$ 23,213	$ 38,404
Sales to related parties	21	686	41	1,228
Income from equity method investments	62	256	109	465
Net gain on disposal of assets	191	12	195	22
Other income	25	45	77	104
Total revenues and other income	13,358	22,202	23,635	40,223
Costs and expenses:				
Cost of revenues (excludes items below)	9,776	17,985	17,133	32,400
Purchases from related parties	110	226	205	365
Consumer excise taxes	1,226	1,295	2,400	2,511
Depreciation, depletion and amortization	701	493	1,363	933
Selling, general and administrative expenses	321	361	612	659
Other taxes	97	127	199	250
Exploration expenses	64	130	126	259
Total costs and expenses	12,295	20,617	22,038	37,377
Income from operations	1,063	1,585	1,597	2,846
Net interest and other financing costs	(11)	(11)	(28)	(4)
Income from continuing operations before income taxes	1,052	1,574	1,569	2,842
Provision for income taxes	711	806	962	1,357
Income from continuing operations	341	768	607	1,485
Discontinued operations	72	6	88	20

Net income	$	413	$	774	$	695	$	1,505
Per Share Data								
Basic:								
Income from continuing operations	$	0.48	$	1.08	$	0.86	$	2.09
Discontinued operations	$	0.10	$	0.01	$	0.12	$	0.02
Net income per share	$	0.58	$	1.09	$	0.98	$	2.11
Diluted:								
Income from continuing operations	$	0.48	$	1.07	$	0.86	$	2.07
Discontinued operations	$	0.10	$	0.01	$	0.12	$	0.03
Net income per share	$	0.58	$	1.08	$	0.98	$	2.10
Dividends paid	$	0.24	$	0.24	$	0.48	$	0.48

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

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MARATHON OIL CORPORATION
Consolidated Balance Sheets (Unaudited)

(In millions, except per share data)	June 30, 2009	December 31, 2008
Assets		
Current assets:		
Cash and cash equivalents	$ 1,496	$ 1,285
Receivables, less allowance for doubtful accounts of $9 and $6	3,857	3,094
Receivables from United States Steel	24	23
Receivables from related parties	48	33
Inventories	3,498	3,507
Other current assets	191	461
Total current assets	9,114	8,403
Equity method investments	2,035	2,080
Receivables from United States Steel	457	469
Property, plant and equipment, less accumulated depreciation, depletion and amortization of $16,394 and $15,581	30,452	29,414
Goodwill	1,423	1,447
Other noncurrent assets	960	873
Total assets	$ 44,441	$ 42,686
Liabilities		
Current liabilities:		
Accounts payable	5,513	4,712
Payables to related parties	29	21
Payroll and benefits payable	310	400
Accrued taxes	499	1,133
Deferred income taxes	615	561
Other current liabilities	704	828
Long-term debt due within one year	103	98
Total current liabilities	7,773	7,753
Long-term debt	8,518	7,087
Deferred income taxes	3,312	3,330
Defined benefit postretirement plan obligations	1,636	1,609
Asset retirement obligations	982	963
Payable to United States Steel	4	4
Deferred credits and other liabilities	403	531
Total liabilities	22,628	21,277
Commitments and contingencies		
Stockholders' Equity		

Preferred stock – 5 million shares issued, 1 million and 3 million shares outstanding (no par value, 6 million shares authorized)		-		-
Common stock:				
Issued – 769 million and 767 million shares (par value $1 per share, 1.1 billion shares authorized)		769		767
Securities exchangeable into common stock – 5 million shares issued, 1 million and 3 million shares outstanding (no par value, unlimited shares authorized)		-		-
Held in treasury, at cost – 61 million and 61 million shares		(2,713)		(2,720)
Additional paid-in capital		6,721		6,696
Retained earnings		17,614		17,259
Accumulated other comprehensive loss		(578)		(593)
Total stockholders' equity		21,813		21,409
Total liabilities and stockholders' equity	$	44,441	$	42,686

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

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MARATHON OIL CORPORATION
Consolidated Statements of Cash Flows (Unaudited)

	Six Months Ended June 30,	
(In millions)	2009	2008
Increase (decrease) in cash and cash equivalents		
Operating activities:		
Net income	$ 695	$ 1,505
Adjustments to reconcile net income to net cash provided by operating activities:		
Income from discontinued operations	(88)	(20)
Deferred income taxes	333	8
Depreciation, depletion and amortization	1,363	933
Pension and other postretirement benefits, net	73	75
Exploratory dry well costs and unproved property impairments	33	114
Net gain on disposal of assets	(195)	(22)
Equity method investments, net	11	(149)
Changes in the fair value of derivative instruments	23	748
Changes in:		
Current receivables	(785)	(1,759)
Inventories	6	(1,737)
Current accounts payable and accrued liabilities	168	3,191
All other, net	78	(49)
Net cash provided by continuing operations	1,715	2,838
Net cash provided by discontinued operations	35	117
Net cash provided by operating activities	1,750	2,955
Investing activities:		
Capital expenditures	(2,939)	(3,329)
Disposal of assets	402	24
Trusteed funds - withdrawals	16	258
Investing activities of discontinued operations	(47)	(53)
All other, net	(51)	(58)
Net cash used in investing activities	(2,619)	(3,158)
Financing activities:		
Short term debt, net	-	980
Borrowings	1,491	1,248
Debt issuance costs	(11)	(7)
Debt repayments	(40)	(1,331)
Purchases of common stock	-	(295)
Dividends paid	(340)	(342)
All other, net	(1)	13
Net cash provided by financing activities	1,099	266
Effect of exchange rate changes on cash:		
Continuing operations	(17)	6
Discontinued operations	(2)	2
Net increase in cash and cash equivalents	211	71

Cash and cash equivalents at beginning of period		1,285		1,199
Cash and cash equivalents at end of period	$	1,496	$	1,270

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

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Notes to Consolidated Financial Statements (Unaudited)

1. Basis of Presentation

These consolidated financial statements are unaudited; however, 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 2009 classifications. Events and transactions subsequent to the balance sheet date have been evaluated through August 6, 2009, the date these consolidated financial statements were issued, for potential recognition or disclosure in the consolidated financial statements.

These interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Marathon Oil Corporation ("Marathon") 2008 Annual Report on Form 10-K. The results of operations for the quarter and six months ended June 30, 2009 are not necessarily indicative of the results to be expected for the full year.

2. New Accounting Standards

SFAS No. 165 – In May 2009, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 165, "Subsequent Events." This statement establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or available to be issued. SFAS No. 165 should not significantly change the subsequent events that an entity reports. It codifies into the accounting standards guidance that existed in the auditing standards. We began applying this standard prospectively in the second quarter of 2009. The disclosures required by SFAS No. 165 appear in Note 1.

FSP FAS 107-1 – In April 2009, the FASB issued a Staff Position ("FSP") FAS 107-1 and APB 28-1, "Interim Disclosures about Fair Value of Financial Instruments" ("FSP FAS 107-1"). FSP FAS 107-1 amends SFAS No. 107 and Accounting Principles Board ("APB") Opinion No. 28 to require disclosures about fair value of financial instruments in interim reporting periods for publicly traded companies. Disclosures are expanded, making the annual disclosures of SFAS No. 107 required in interim periods. This FSP is effective for the second quarter of 2009 and does not require disclosures for earlier periods presented for comparative purposes. Adoption did not have an impact on our consolidated results of operations, financial position or cash flows. The required disclosures are presented in Note 10.

FSP FAS 157-4 – Also in April 2009, the FASB issued FSP FAS 157-4, "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly,". FSP FAS 157-4 provides additional guidance for estimating fair value in accordance with SFAS No. 157 when the volume and level of activity for the asset or liability has significantly decreased. It also includes guidance on identifying circumstances that indicate a transaction is not orderly. FSP FAS 157-4 is effective for the second quarter of 2009 and does not require disclosures for earlier periods presented for comparative purposes. Adoption did not have a significant impact on our consolidated results of operations, financial position or cash flows.

EITF 08-6 – In November 2008, the FASB ratified Emerging Issues Task Force ("EITF") Issue 08-6, "Equity Method Investment Accounting Considerations" ("EITF 08-6") which clarifies how to account for certain transactions involving equity method investments. The initial measurement, decreases in value and changes in the level of ownership of the equity method investment are addressed. EITF 08-6 is effective on a prospective basis on January 1, 2009 and for interim periods. Early application by an entity that has previously adopted an alternative accounting policy is not permitted. Since this standard will be applied prospectively, adoption did not have a significant impact on our consolidated results of operations, financial position or cash flows.

FSP EITF 03-6-1 – In June 2008, the FASB issued FSP EITF 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities" 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. While our restricted stock awards meet this definition of participating securities, the application of FSP EITF 03-6-1 did not have a significant impact on our reported EPS.

FSP FAS 142-3 – In April 2008, the FASB issued FSP FAS 142-3, "Determination of the Useful Life of Intangible Assets" ("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 is applied prospectively, adoption did not have a significant impact on our consolidated results of operations, financial position or cash flows.

SFAS No. 161 – 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. The disclosures required by SFAS No. 161 appear in Note 11.

SFAS No. 141(R) – 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 noncontrolling 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 standard on business combinations. 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. In April 2009, the FASB issued an FSP on FAS 141(R), "Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies" ("FSP FAS 141(R)-1"), which addressed SFAS No. 141(R) implementation issues related to contingent assets and liabilities acquired in a business combination. Both SFAS No. 141(R) and FSP FAS 141(R)-1 are effective on January 1, 2009 for all new business combinations. Because we had no business combinations in progress at January 1, 2009, adoption of these standards did not have a significant impact on our consolidated results of operations, financial position or cash flows.

SFAS No. 160 – 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. In January 2009, the FASB ratified EITF Issue 08-10, “Selected Statement 160 Implementation Questions” (“EITF 08-10”). Both SFAS No. 160 and EITF 08-10 are effective January 1, 2009. The statements must be applied prospectively, except for the presentation and disclosure requirements which must be applied retrospectively for all periods presented in consolidated financial statements. Adoption of these standards did not have a significant impact on our consolidated results of operations, financial position or cash flows.

SFAS No. 157 – 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. We adopted SFAS No. 157 effective January 1, 2008 with respect to financial assets and liabilities and effective January 1, 2009 with respect to nonfinancial assets and

Notes to Consolidated Financial Statements (Unaudited)

liabilities. Adoption did not have a significant effect on our consolidated results of operations, financial position or cash flows.

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 deferred 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.

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," 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 was effective upon issuance, including prior periods for which financial statements had not been issued, and any revisions resulting from a change in the valuation technique or its application were required to 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.

The additional disclosures regarding assets and liabilities recorded at fair value and measured under SFAS No. 157 are presented in Note 10.

FSP FASB 132(R)-1 – In December 2008, the FASB issued FSP FAS 132(R)-1, "Employers' Disclosures about Postretirement Benefit Plan Assets" ("FSP FAS 132(R)-1") which provides guidance on an employer's disclosures about plan assets of defined benefit pension or other postretirement plans. This FSP requires additional disclosures about investment policies and strategies, the reporting of fair value by asset category and other information about fair value measurements. The FSP is effective January 1, 2009 and early application is permitted. Upon initial application, the provisions of FSP FAS 132(R)-1 are not required for earlier periods that are presented for comparative purposes. We will expand our disclosures in accordance with FSP FAS 132(R)-1 in our Annual Report on Form 10-K for the year ending December 31, 2009; however, the adoption of this standard is not expected to have an impact on our consolidated results of operations, financial position or cash flows.

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, provided the effect is not antidilutive.

	Three Months Ended June 30,	
	2009	2008

(In millions, except per share data)	Basic	Diluted	Basic	Diluted
Income from continuing operations	$ 341	$ 341	$ 768	$ 768
Discontinued operations	72	72	6	6
Net income	$ 413	$ 413	$ 774	$ 774
Weighted average common shares outstanding	709	709	710	710
Effect of dilutive securities	-	2	-	4
Weighted average common shares, including dilutive effect	709	711	710	714
Per share:				
Income from continuing operations	$ 0.48	$ 0.48	$ 1.08	$ 1.07
Discontinued operations	$ 0.10	$ 0.10	$ 0.01	$ 0.01
Net income	$ 0.58	$ 0.58	$ 1.09	$ 1.08

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Notes to Consolidated Financial Statements (Unaudited)

	Six Months Ended June 30,			
	2009		2008	
(In millions, except per share data)	Basic	Diluted	Basic	Diluted
Income from continuing operations	$ 607	$ 607	$ 1,485	$ 1,485
Discontinued operations	88	88	20	20
Net income	$ 695	$ 695	$ 1,505	$ 1,505
Weighted average common shares outstanding	709	709	711	711
Effect of dilutive securities	-	2	-	5
Weighted average common shares, including dilutive effect	709	711	711	716
Per share:				
Income from continuing operations	$ 0.86	$ 0.86	$ 2.09	$ 2.07
Discontinued operations	$ 0.12	$ 0.12	$ 0.02	$ 0.03
Net income	$ 0.98	$ 0.98	$ 2.11	$ 2.10

The per share calculations above exclude 8 million stock options for the second quarter and the first six months of 2009 and 6 million stock options for the second quarter and the first six months of 2008, as they were antidilutive.

4. Dispositions

Ireland disposition - In April 2009, we closed the sale of our operated properties in Ireland for net proceeds of $84 million, after adjusting for cash held by the sold subsidiary. A $158 million pretax gain on the sale was recorded. As a result of this sale, we terminated our pension plan in Ireland, incurring a charge of $18 million. Activities related to our operated properties in Ireland had been reported in our Exploration and Production ("E&P") segment.

On June 24, 2009 we entered into an agreement to sell the subsidiary holding our 19 percent outside-operated interest in the Corrib natural gas development offshore Ireland. Activities related to the Corrib development also had been reported in our E&P segment. Total proceeds will range between $235 million and $400 million, subject to the timing of first commercial gas at Corrib and closing adjustments. At closing on July 30, 2009, the initial $100 million payment plus closing adjustments was received. Additional proceeds of $135 million to $300 million will be received on the earlier of first commercial gas or December 31, 2012. The fair value of the consideration for this asset was $311 million which was less than its book value. An impairment of $154 million was recognized in the second quarter of 2009 in discontinued operations. Additional gains or losses may be recognized until the final proceeds payment is received (see Note 10).

As a result of these dispositions, our Irish exploration and production businesses have been reported as discontinued operations in the consolidated statements of income and the consolidated statements of cash flows for all periods presented. The net loss on the sales reported in discontinued operations for 2009 was $14 million before income taxes. Revenues and pretax income associated with the operations are shown in the following table:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2009	2008	2009	2008
Revenues applicable to discontinued operations	$ 4	$ 23	$ 83	$ 102
Pretax income (loss) from discontinued operations	$ (2)	$ 10	$ 33	$ 40

Existing guarantees of our subsidiaries' performance issued to Irish government entities will remain in place after the sales until the purchaser issues similar guarantees to replace them. The guarantees, related to asset retirement obligations and natural gas production levels, have been indemnified by the purchaser. Our maximum potential undiscounted payments under these guarantees were $155 million as of June 30, 2009.

Permian Basin disposition - In June 2009, we closed the sales of a portion of our operated and all of our outside-operated Permian Basin producing assets in New Mexico and west Texas for net proceeds after closing adjustments of

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$292 million. A $199 million pretax gain on the sale was recorded. Activities related to these assets also had been reported in our E&P segment.

Pending Angola disposition - In July 2009, we entered into an agreement to sell an undivided 20 percent outside-operated interest in the Production Sharing Contract and Joint Operating Agreement in Block 32 offshore Angola for $1.3 billion, excluding any purchase price adjustments at closing, with an effective date of January 1, 2009. We will retain a 10 percent outside-operated interest in Block 32. The carrying value of the 20 percent interest at June 30, 2009 was $430 million which will be classified as held for sale beginning August 1, 2009. We expect to close the transaction by year end 2009, subject to government and regulatory approvals. Activities related to these assets are being reported in our E&P segment.

Assets held for sale - As of June 30, 2009, assets held for sale primarily represented our outside-operated interest in the Corrib development in Ireland as shown in the following table:

(In millions)		
Other current assets	$	1
Other noncurrent assets		373
Total assets		374
Other current liabilities		52
Deferred credits and other liabilities		9
Total liabilities		61
Net assets held for sale	$	313

5. Segment Information

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

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

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

As discussed in Note 4, our Irish businesses have been reported as discontinued operations. Segment information for all presented periods excludes amounts for these operations.

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Notes to Consolidated Financial Statements (Unaudited)

	Three Months Ended June 30, 2009				
(In millions)	E&P	OSM	RM&T	IG	Total
Revenues:					
Customer	$ 1,871	$ 126	$ 11,052	$ 7	$ 13,056
Intersegment (a)	123	29	8	-	160
Related parties	14	-	7	-	21
Segment revenues	2,008	155	11,067	7	13,237
Elimination of intersegment revenues	(123)	(29)	(8)	-	(160)
Gain on U.K. natural gas contracts	3	-	-	-	3
Total revenues	$ 1,888	$ 126	$ 11,059	$ 7	$ 13,080
Segment income	$ 220	$ 2	$ 165	$ 13	$ 400
Income from equity method investments(b)	26	-	8	28	62
Depreciation, depletion and amortization (c)	502	34	157	1	694
Income tax provision (c)	444	-	104	2	550
Capital expenditures (d)	617	281	713	1	1,612

	Three Months Ended June 30, 2008				
(In millions)	E&P	OSM	RM&T	IG	Total
Revenues:					
Customer	$ 3,160	$ (80)	$ 18,267	$ 21	$ 21,368
Intersegment (a)	226	96	37	-	359
Related parties	15	-	671	-	686
Segment revenues	3,401	16	18,975	21	22,413
Elimination of intersegment revenues	(226)	(96)	(37)	-	(359)
Loss on U.K. natural gas contracts	(165)	-	-	-	(165)
Total revenues	$ 3,010	$ (80)	$ 18,938	$ 21	$ 21,889
Segment income (loss)	$ 822	$ (157)	$ 158	$ 102	$ 925
Income from equity method investments(b)	77	-	43	136	256
Depreciation, depletion and amortization (c)	300	33	150	1	484
Income tax provision (benefit)(c)	851	(54)	108	36	941
Capital expenditures (d)	839	262	702	-	1,803

	Six Months Ended June 30, 2009				
(In millions)	E&P	OSM	RM&T	IG	Total
Revenues:					
Customer	$ 3,175	$ 223	$ 19,712	$ 18	$ 23,128
Intersegment (a)	242	54	17	-	313
Related parties	29	-	12	-	41

Segment revenues		3,446		277		19,741		18		23,482
Elimination of intersegment revenues		(242)		(54)		(17)		-		(313)
Gain on U.K. natural gas contracts		85		-		-		-		85
Total revenues	$	3,289	$	223	$	19,724	$	18	$	23,254
Segment income (loss)	$	305	$	(22)	$	324	$	40	$	647
Income from equity method investments(b)		37		-		2		70		109
Depreciation, depletion and amortization (c)		969		71		309		2		1,351
Income tax provision (benefit)(c)		616		(8)		210		15		833
Capital expenditures (d)		990		567		1,373		1		2,931

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	Six Months Ended June 30, 2008				
(In millions)	E&P	OSM	RM&T	IG	Total
Revenues:					
Customer	$ 5,900	$ 99	$ 32,600	$ 40	$ 38,639
Intersegment (a)	385	116	202	-	703
Related parties	29	-	1,199	-	1,228
Segment revenues	6,314	215	34,001	40	40,570
Elimination of intersegment revenues	(385)	(116)	(202)	-	(703)
Loss on U.K. natural gas contracts	(235)	-	-	-	(235)
Total revenues	$ 5,694	$ 99	$ 33,799	$ 40	$ 39,632
Segment income (loss)	$ 1,494	$ (130)	$ 83	$ 201	$ 1,648
Income from equity method investments(b)	139	-	71	255	465
Depreciation, depletion and amortization (c)	548	67	298	2	915
Income tax provision (benefit)(c)	1,521	(45)	63	84	1,623
Capital expenditures (d)	1,596	510	1,213	1	3,320

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

(b) Pilot Travel Centers LLC, which was reported in our RM&T segment, was sold in the fourth quarter of 2008.

(c) 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.

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2009	2008	2009	2008
Segment income	$ 400	$ 925	$ 647	$ 1,648
Items not allocated to segments, net of income taxes:				
Corporate and other unallocated items	(89)	(57)	(140)	(78)
Foreign currency remeasurement of deferred taxes	(94)	(16)	(66)	35
	2	(84)	44	(120)

Gain (loss) on U.K. natural gas contracts				
Gain on dispositions	122	-	122	-
Discontinued operations	72	6	88	20
Net income	$ 413	$ 774	$ 695	$ 1,505

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 June 30,		Six Months Ended June 30,	
(In millions)	2009	2008	2009	2008
Total revenues	$ 13,080	$ 21,889	$ 23,254	$ 39,632
Less: Sales to related parties	21	686	41	1,228
Sales and other operating revenues (including consumer excise taxes)	$ 13,059	$ 21,203	$ 23,213	$ 38,404

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6. Defined Benefit Postretirement Plans

The following summarizes the components of net periodic benefit cost:

	Three Months Ended June 30,							
	Pension Benefits				Other Benefits			
(In millions)	2009		2008		2009		2008	
Service cost	$	37	$	39	$	4	$	4
Interest cost		42		41		9		10
Expected return on plan assets		(40)		(42)		-		-
Amortization:								
– prior service cost (credit)		4		4		(2)		-
– actuarial loss (gain)		10		11		(2)		(2)
– net settlement/curtailment loss(a)		18		-		-		-
Net periodic benefit cost	$	71	$	53	$	9	$	12

	Six Months Ended June 30,							
	Pension Benefits				Other Benefits			
(In millions)	2009		2008		2009		2008	
Service cost	$	72	$	73	$	9	$	9
Interest cost		84		80		20		22
Expected return on plan assets		(80)		(84)		-		-
Amortization:								
– prior service cost (credit)		7		7		(3)		(4)
– actuarial loss (gain)		16		15		(2)		1
– net settlement/curtailment loss(a)		18		-		-		-
Net periodic benefit cost	$	117	$	91	$	24	$	28

(a) The curtailment and settlement is related to our discontinued operations in Ireland, as discussed in Note 4. Pension expense related to Ireland was not material in any period presented.

During the first six months of 2009, we made contributions of $40 million to our funded pension plans. We expect to make additional contributions up to an estimated $290 million to our funded pension plans over the remainder of 2009, the majority of which will occur in the third quarter of 2009. We are still evaluating guidance issued by the Internal Revenue Service on March 31, 2009, which may cause actual contributions to differ from our estimate. Current benefit payments related to unfunded pension and other postretirement benefit plans were $8 million and $16 million during the first six months of 2009.

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7. Income Taxes

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

	Six Months Ended June 30,	
	2009	2008
Statutory U.S. income tax rate	35%	35%
Foreign taxes in excess of federal statutory rate	25	14
State and local income taxes, net of federal income tax effects	1	1
Other tax effects	-	(2)
Effective income tax rate	61%	48%

The effective income tax rate is influenced by a variety of factors including the geographic and functional sources of income, the relative magnitude of these sources of income, and foreign currency remeasurement effects. The change in mix of liquid hydrocarbon and natural gas sales in 2009 from 2008 included more sales in jurisdictions with high tax rates. This change, as well as unfavorable foreign currency remeasurement effects, contributed to the increase in the effective income tax rate in the first six months of 2009 when compared to the same period in 2008.

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 June 30, 2009, 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 - 2008
Equatorial Guinea	2006 - 2008
Libya	2006 - 2008
Norway	2007 - 2008
United Kingdom	2007

(a) Includes federal and state jurisdictions.

8. Comprehensive Income

The following sets forth comprehensive income for the periods indicated:

	Three Months Ended	Six Months Ended

	June 30,		June 30,	
(In millions)	2009	2008	2009	2008
Net income	$ 413	$ 774	$ 695	$ 1,505
Other comprehensive income, net of taxes:				
Defined benefit postretirement plans	19	(31)	18	(20)
Derivatives	26	1	(4)	4
Other	-	-	1	(5)
Comprehensive income	$ 458	$ 744	$ 710	$ 1,484

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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)	June 30, 2009	December 31, 2008
Liquid hydrocarbons, natural gas and bitumen	$ 1,122	$ 1,376
Refined products and merchandise	1,935	1,797
Supplies and sundry items	441	334
Total, at cost	$ 3,498	$ 3,507

10. Fair Value Measurements

Fair Values - Recurring

The following table presents the assets (liabilities) accounted for at fair value on a recurring basis as of June 30, 2009, and December 31, 2008:

	June 30, 2009			
(In millions)	Level 1	Level 2	Level 3	Total
Derivative Instruments:				
Commodity	$ 18	$ 1	$ (6)	$ 13
Interest rate	-	-	(23)	(23)
Foreign currency	-	(22)	-	(22)
Total derivative instruments	18	(21)	(29)	(32)
Other assets	2	-	-	2
Total at fair value	$ 20	$ (21)	$ (29)	$ (30)

	December 31, 2008			
(In millions)	Level 1	Level 2	Level 3	Total
Derivative Instruments:				
Commodity	$ 107	$ 6	$ (55)	$ 58
Interest rate	-	-	29	29
Foreign currency	-	(75)	-	(75)
Total derivative instruments	107	(69)	(26)	12
Other assets	2	-	-	2
Total at fair value	$ 109	$ (69)	$ (26)	$ 14

Deposits of $17 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 at June 30, 2009 include two U.K. natural gas sales contracts that are accounted for as derivative instruments and 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

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and the U.K. forward natural gas strip price to the expected sales volumes for the remaining contract term. 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.

Also in Level 3 are commodity derivatives intended to manage price risk related to acquisition of ethanol for blending and light products fixed priced sales contracts. The fair value of these derivatives is measured using quoted market prices adjusted for broker market assessments.

The fair value of interest rate swaps is measured using broker quotes or quotes from a reporting service which are not corroborated to data from an active market; therefore these inputs are classified as Level 3.

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 six months ended June 30, 2009:

(In millions)	Three Months Ended June 30, 2009
Beginning balance	$ 9
Total realized and unrealized losses:	
Included in net income	(33)
Purchases, sales, issuances and settlements, net	(5)
Ending balance	$ (29)

(In millions)	Six Months Ended June 30, 2009
Beginning balance	$ (26)
Total realized and unrealized losses:	
Included in net income	44
Purchases, sales, issuances and settlements, net	(47)
Ending balance	$ (29)

Net income for the second quarter and first six months of 2009 included unrealized losses of $4 million and unrealized gains of $76 million, respectively, related to instruments held at June 30, 2009. 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 capital expenditures.

Fair Values - Nonrecurring

The following table shows the June 30, 2009 values of assets measured at fair value on a nonrecurring basis during the second quarter of 2009 by major category:

	June 30, 2009				
(In millions)	Total	Level 1	Level 2	Level 3	Impairment
Long-lived assets held for sale	$ 311	$ -	$ -	$ 311	$ 154
Long-lived assets held for use	5	-	-	5	15

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The impairment charge related to the sale of the Corrib natural gas development offshore Ireland was based on a fair value assessment of the anticipated sale proceeds (see Note 4). At closing on July 30, 2009, the initial $100 million payment was received. Additional proceeds of $135 million to $300 million will be received on the earlier of first commercial gas or December 31, 2012. These proceeds were classified as Level 3 inputs because a portion is variable in timing and amount depending upon timing of first gas. The Level 3 inputs were valued using an income method that incorporated a probability-weighted approach with respect to timing of first commercial gas and an associated sliding scale on the amount of corresponding consideration specified in the sales agreement: the longer it takes to achieve first gas, the lower the amount of the consideration. The minimum amount due of $135 million is payable no later than December 31, 2012.

The ultimate timing of the gain or loss recognized related to the sale of the Corrib development will depend on the resolution by accounting standard-setters of the appropriate accounting for contingent consideration. The EITF is currently deliberating the appropriate accounting treatment for contingent consideration by sellers. In connection with that deliberation, the EITF has asked the FASB staff for interpretative guidance on the initial recognition of contingent consideration by sellers. The timing of any further gain or loss recognition will depend on the resolution reached by the FASB staff and the EITF and may or may not require a reassessment of the fair value of the contingent consideration each reporting period.

Several long-lived assets held for use were evaluated for impairment in the second quarter of 2009 due to reductions in estimated reserves and declining natural gas prices. An impairment was required on one natural gas field in East Texas. Fair value of the asset was measured using an income approach based upon internal estimates of future production levels, prices and discount rate, which are Level 3 inputs.

Fair Values - Reported

The following table summarizes financial instruments, excluding the derivative financial instruments, and their reported fair value by individual balance sheet line item at June 30, 2009 and December 31, 2008:

	June 30, 2009		December 31, 2008	
	Fair	Carrying	Fair	Carrying
(In millions)	Value	Amount	Value	Amount
Financial assets				
Receivables from United States Steel, including current portion	$ 470	$ 481	$ 438	$ 492
Other noncurrent assets(a)	405	217	286	113

Total financial assets	875	698	724	605
Financial liabilities				
Long-term debt, including current portion(b)	8,508	8,333	5,683	6,854
Total financial liabilities	$ 8,508	$ 8,333	$ 5,683	$ 6,854

(a) Includes restricted cash, cost method investments and miscellaneous long-term receivables or deposits of which $132 million related to deposits in property exchange trusts.

(b) Excludes capital leases.

Our current assets and liabilities accounts contain financial instruments, the most significant of which are trade accounts receivables and payables. We believe the carrying values of our current assets and liabilities approximate fair value, with the exception of the current portion of receivables from United States Steel and the current portion of our long-term debt, which is reported above. Our fair value assessment incorporates a variety of considerations, including (1) the short-term duration of the instruments, (2) our investment-grade credit rating, and (3) our historical incurrence of and expected future insignificance of bad debt expense, which includes an evaluation of counterparty credit risk.

The fair value of the receivables from United States Steel is measured using an income approach that discounts the future expected payments over the remaining term of the obligations. Because this asset is not publicly-traded and not

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easily transferable, a hypothetical market based upon United States Steel's borrowing rate curve is assumed and the majority of inputs to the calculation are Level 3. The industrial revenue bonds are to be redeemed on or before December 31, 2011.

The majority of our restricted cash represents cash accounts that earn interest or will be held for a short time; therefore, the balance approximates fair value. Other financial assets included in the other noncurrent assets line include cost method investments and miscellaneous long-term receivables or deposits. Fair value for the cost method investments is measured using an income approach. Estimated future cash flows, obtained from the partially owned companies, are discounted at an appropriate discount rate to obtain the fair value. We may adjust the companies' estimates based upon current market conditions. Long-term receivables and deposits are measured using an income approach. The expected timing of payments is scheduled and then discounted using a rate deemed appropriate.

Over 75 percent of our long-term debt instruments are publicly-traded. A market approach, based upon quotes from major financial institutions is used to measure the fair value of such debt. Because these quotes cannot be independently verified to the market they are considered Level 3 inputs. The fair value of our debt that is not publicly-traded is measured using an income approach. The future debt service payments are discounted using the rate at which we currently expect to borrow. All inputs to this calculation are Level 3.

11. Derivatives

We may use derivatives to manage our exposure to commodity price risk, interest rate risk and foreign currency risk. Derivative instruments are recorded at fair value. Derivative instruments on our consolidated balance sheet are reported on a net basis by brokerage firm, as permitted by master netting agreements. For further information regarding the fair value measurement of derivative instruments see Note 10. The following table presents the gross fair values of derivative instruments, excluding cash collateral, and where they appear on the consolidated balance sheet as of June 30, 2009:

(In millions)	Asset	Liability	Net Asset	Balance Sheet Location
Cash Flow Hedges				
Foreign currency	$ 1	$ -	$ 1	Other current assets
Total Designated Hedges	1	-	1	
Not Designated as Hedges				
Commodity	292	(270)	22	Other current assets
Total Not Designated as Hedges	292	(270)	22	
Total	$ 293	$ (270)	$ 23	

(In millions)	Asset	Liability	Net Liability	Balance Sheet Location
Cash Flow Hedges				

Foreign currency	$	-	$	(23)	$	(23)	Other current liabilities
Fair Value Hedges							
Commodity		-		(7)		(7)	Other current liabilities
Interest rate		-		(23)		(23)	Deferred credits and other liabilities
Total Designated Hedges		-		(53)		(53)	
Not Designated as Hedges							
Commodity		8		(27)		(19)	Other current liabilities
Total Not Designated as Hedges		8		(27)		(19)	
Total	$	8	$	(80)	$	(72)	

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Derivatives Designated as Cash Flow Hedges

We also use foreign currency forwards and options to hedge anticipated transactions, primarily expenditures for capital projects, in certain foreign currencies and designate them cash flow hedges. As of June 30, 2009, the following foreign currency forwards were outstanding:

(In millions)	Period		Notional Amount	Weighted Average Forward Rate
Foreign Currency Forwards:				
Dollar (Canada)	July 2009 - February 2010	$	275	1.069 (b)
Euro	July 2009- June 2010	$	6	1.278 (a)
Kroner (Norway)	July 2009 - November 2009	$	40	6.285 (b)

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

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

We may use interest rate derivative instruments to manage the market risk of interest rate movements on anticipated borrowings. No such derivatives were outstanding at June 30, 2009. In recent past transactions, such derivatives have been outstanding for a period of less than one month.

For derivatives qualifying as hedges of future cash flows, the effective portion of any changes in fair value is recognized in other comprehensive income ("OCI") and is reclassified to net income when the underlying forecasted transaction is recognized in net income. Any ineffective portion of cash flow hedges is recognized in net income as it occurs. For discontinued cash flow hedges, prospective changes in the fair value of the derivative are recognized in net income. The accumulated gain or loss recognized in OCI at the time a hedge is discontinued continues to be deferred until the original forecasted transaction occurs. However, if it is determined that the likelihood of the original forecasted transaction occurring is no longer probable, the entire accumulated gain or loss recognized in OCI is immediately reclassified into net income.

Approximately $1 million in losses are expected to be reclassified from accumulated other comprehensive income ("AOCI") over the next 12 months. The ineffective portion of currently outstanding cash flow hedges was less than $1 million; therefore, ineffectiveness is not reported in the tables below. In the second quarter and six months ended June 30, 2009, no significant cash flow hedges were discontinued.

The following table summarizes the effect of derivative instruments designated as hedges of cash flows in other comprehensive income:

	Gain (Loss) in OCI

(In millions)		Three Months Ended		Six Months Ended
Foreign currency	$	30	$	18
Interest rate	$	-	$	(15)

The following table summarizes the effect of AOCI reclasses related to derivative instruments designated as hedges of cash flows in our consolidated statement of income:

		Gain (Loss) reclassified from AOCI into Net Income			
(In millions)	Income Statement Location		Three Months Ended		Six Months Ended
Foreign currency	Discontinued operations	$	1	$	1
Interest rate	Net interest and other financing costs	$	-	$	(1)

Derivatives Designated as Fair Value Hedges

We use interest rate swaps to manage the mix of fixed and floating interest rate debt in our portfolio. As of June 30, 2009, we had multiple interest rate swap agreements with a total notional amount of $1.25 billion at a weighted-average, LIBOR-based, floating rate of 4.49 percent. For such derivatives designated as hedges of fair value, changes in

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the fair values of both the hedged item and the related derivative are recognized immediately in net income with an offsetting effect included in the basis of the hedged item. The net effect is to report in net income the extent to which the hedge is not effective in achieving offsetting changes in fair value.

We use commodity derivative instruments to manage the price risk for natural gas that is purchased to be marketed with our own natural gas production. These are also designated as fair value hedges. As of June 30, 2009, commodity derivative instruments for a weighted average 5,000 mcf ("thousand cubic feet") were outstanding for the period July 2009 through March 2010.

The following table summarizes the pretax effect of derivative instruments designated as hedges of fair value in our consolidated statement of income for the three months and six months ended June 30, 2009:

		Gain (Loss)	
(In millions)	Income Statement Location	Three Months Ended	Six Months Ended
Derivative			
Commodity	Sales and other operating revenues	$ (4)	$ (10)
Interest rate	Net interest and other financing costs	(29)	(29)
		(33)	(39)
Hedged Item			
Commodity	Sales and other operating revenues	4	10
Interest rate	Net interest and other financing costs	29	29
		33	39

The interest rate swaps have no hedge ineffectiveness. Hedge ineffectiveness related to the commodity derivatives is less than $1 million and is therfore not reflected in the above table.

Derivatives not Designated as Hedges

Changes in the fair value of derivatives not designated as hedges are recognized immediately in net income. Some derivative instruments not designated as hedges may be classified as trading activities, for which all related effects, are recognized in net income and are classified as other income.

Two long-term natural gas delivery commitment contracts in the U.K. are classified as derivative instruments. These contracts, which expire September 2009, contain pricing provisions that are not clearly and closely related to the underlying commodity and therefore must be accounted for as derivative instruments. Crude oil options entered by Western Oil Sands Inc. ("Western") to protect against price decreases on a portion of future sales of synthetic crude oil were not designated as hedges upon our acquisition of Western in October 2007. In the first quarter of 2009, we sold derivative instruments which effectively offset the open put options for the remainder of 2009. The following table summarizes the put and call options outstanding at June 30, 2009:

Option Contract Volumes (Barrels per day)		
Put options purchased		20,000
Put options sold		20,000
Call options sold		15,000
Average Exercise Price (Dollars per barrel)		
Put options	$	50.50
Call options	$	90.50

We use commodity derivative instruments to manage price risk on inventories and natural gas held in storage before it is sold. We also use derivative instruments to manage price risk related to fixed price sales of refined products, the acquisition of foreign-sourced crude oil, the acquisition of feedstocks used in the refining process and the acquisition of ethanol for blending with refined products. The following table summarizes volumes related to our net open positions as of June 30, 2009:

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	Buy/(Sell)
Crude oil (million barrels)	2.1
Refined products (million barrels)	3.6
Natural gas (billion cubic feet)	
Price	(2.4)
Basis	(1.3)

The following table summarizes the effect of all derivative instruments not designated as hedges in our consolidated statement of income for the three months and six months ended June 30, 2009:

		Gain (Loss)	
(In millions)	Income Statement Location	Three Months Ended	Six Months Ended
Commodity	Sales and other operating revenues	$ (1)	$ 92
Commodity	Cost of revenues	17	(42)
Commodity	Other income	2	3
		18	53

Contingent Credit Features

Our derivative instruments contain no significant contingent credit features.

Concentrations of Credit Risk

All of our financial instruments, including derivatives, involve elements of credit and market risk. The most significant portion of our credit risk relates to nonperformance by counterparties. The counterparties to our financial instruments consist primarily of major financial institutions and companies within the energy industry. To manage counterparty risk associated with financial instruments, we select and monitor counterparties based on our assessment of their financial strength and on credit ratings, if available. Additionally, we limit the level of exposure with any single counterparty.

12. Debt

At June 30, 2009, we had no borrowings against our revolving credit facility and no commercial paper outstanding under our U.S. commercial paper program that is backed by the revolving credit facility.

On February 17, 2009, we issued $700 million aggregate principal amount of senior notes bearing interest at 6.5 percent with a maturity date of February 15, 2014 and $800 million aggregate principal amount of senior notes bearing interest at 7.5 percent with a maturity date of February 15, 2019. Interest on both issues is payable semi-annually beginning August 15, 2009.

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13. Stock-Based Compensation Plans

The following table presents a summary of stock option award and restricted stock award activity for the six month period ended June 30, 2009:

	Stock Options		Restricted Stock	
	Number of Shares	Weighted Average Exercise Price	Awards	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2008	13,841,748	$ 37.59	2,049,255	$ 47.72
Granted (a)	4,970,500	27.62	227,935	24.15
Options Exercised/Stock Vested	(28,610)	15.86	(282,291)	43.13
Canceled	(141,990)	52.41	(69,995)	43.15
Outstanding at June 30, 2009	18,641,648	$ 34.85	1,924,904	$ 45.77

(a) The weighted average grant date fair value of stock option awards granted was $7.67 per share.

14. 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.

Litigation – We settled a number of lawsuits pertaining to methyl tertiary-butyl ether (“MTBE”) in 2008. Presently, we are a defendant, along with other refining companies, in 26 cases arising in four states alleging damages for MTBE contamination. Of the 26 cases in which we remain a defendant, 20 are pending in New York, 4 in Florida and 1 in Illinois. These 25 cases allege damages to water supply wells, similar to the damages claimed in the cases that were settled in 2008. 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 we are a defendant and natural resources damages are sought. Thirteen of the 20 New York cases have been dismissed from the multi-district litigation (“MDL”) and re-filed in the state courts of Nassau and Suffolk Counties, New York. The remaining cases, like the cases that were settled in 2008, are consolidated in the MDL in the Southern District of New York for pretrial proceedings. We are vigorously defending these cases. We have engaged in settlement discussions related to the majority of the cases. We do not expect our share of liability, if any, for the remaining cases to significantly impact our consolidated results of operations, financial position or cash flows. We voluntarily discontinued producing MTBE in 2002.

We are currently a party in two qui tam cases, which allege that federal and Indian leases violated the False Claims Act with respect to the reporting and payment of royalties on natural gas and natural gas liquids. A qui tam action is an action in which the relator files suit on behalf of himself as well as the federal government. One case is U.S. ex rel Harrold E. Wright v. Agip Petroleum Co. et al. which is primarily a gas valuation case. A settlement agreement has been reached, but not yet finalized. Such settlement is not expected to significantly impact our consolidated results of operations, financial position or cash flows. The other case is U.S. ex rel Jack Grynberg v. Alaska Pipeline, et al. involving allegations of natural gas measurement. This case was dismissed by the trial court and the dismissal has been affirmed by the 10th Circuit Court of Appeals. The relator is expected to file an appeal to the U.S. Supreme Court. The outcome of this case is not expected to significantly impact our consolidated results of operations, financial position or cash flows.

A lawsuit filed in the U.S. District Court for the Southern District of West Virginia alleged that our 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 there was no permanent damage to wholesaler and retailer equipment. Class action certification was granted in August 2007. A settlement of the case was approved by the court on March 18, 2009, payment has been

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made and the case has been dismissed with prejudice. The settlement did not significantly impact our consolidated results of operations, financial position or cash flows.

Contractual commitments – At June 30, 2009, Marathon's contract commitments to acquire property, plant and equipment totaled $3,407 million.

15. Supplemental Cash Flow Information

	Six Months Ended June 30,	
(In millions)	2009	2008
Net cash provided from operating activities included:		
Interest paid (net of amounts capitalized)	$ -	$ 54
Income taxes paid to taxing authorities	1,050	1,498
Short term debt, net:		
Commercial paper - issuances	$ 897	$ 28,992
- repayments	(897)	(28,012)
Noncash investing and financing activities:		
Capital lease and sale-leaseback financing obligations	$ 47	$ 32

16. Accounting Standards Not Yet Adopted

SFAS No. 167 – In June 2009, the Financial Accounting Standards Board issued Statement of Financial Accounting Standard ("SFAS") No. 167, "Amendments of FASB Interpretation No. 46(R)." This statement replaces the existing quantitative-based risks and rewards calculation for determining which enterprise has a controlling financial interest in a variable interest entity with an approach focused on identifying which enterprise has the power to direct the activities of a variable interest entity. In addition, the concept of qualifying special-purpose entities has been eliminated and therefore, will now be evaluated for consolidation in accordance with the applicable consolidation guidance. Ongoing assessments of whether an enterprise is the primary beneficiary of a variable interest entity are also required. SFAS No. 167 requires reconsideration for determining whether an entity is a variable interest entity when changes in facts and circumstances occur such that the holders of the equity investment at risk, as a group, lack the power from voting rights or similar rights to direct the activities of the entity. Enhanced disclosures are required for any enterprise that holds a variable interest in a variable interest entity. SFAS No. 167 will be applied prospectively beginning in the first quarter of 2010, and for all interim and annual periods thereafter. Earlier application of SFAS No. 167 is prohibited. We are currently evaluating the provisions of this statement.

Reporting on Oil & Gas Producing Activities – In December 2008, the SEC announced that it had approved revisions to its oil and gas reporting disclosures. The new disclosure requirements include provisions that:

- Introduce a new definition of oil and gas producing activities. This new definition allows companies to include volumes in their reserve base from unconventional resources. Such unconventional resources include bitumen extracted from oil sands and oil and gas extracted from coal beds and shale formations.

- Report oil and gas reserves using an unweighted average price using the prior 12-month period, based on the closing prices on the first day of each month, rather than year-end prices. The SEC indicated that they will continue to communicate with the FASB staff to align their accounting standards with these rules. The FASB currently requires a single-day, year-end price for accounting purposes.

- Permit companies to disclose their probable and possible reserves on a voluntary basis. Under current rules, proved reserves were the only reserves allowed in the disclosures.

- Require companies to provide additional disclosure regarding the aging of proved undeveloped reserves.

- Permit the use of reliable technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes.

- Replace the existing "certainty" test for areas beyond one offsetting drilling unit from a productive well with a "reasonable certainty" test.

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- Require additional disclosures regarding the qualifications of the chief technical person who oversees the company's overall reserve estimation process. Additionally, disclosures regarding internal controls surrounding reserve estimation, as well as a report addressing the independence and qualifications of its reserves preparer or auditor will be mandatory.

- Require separate disclosure of reserves in foreign countries if they represent more than 15 percent of total proved reserves, based on barrels of oil equivalents.

We expect to begin complying with the disclosure requirements in our Annual Report on Form 10-K for the year ending December 31, 2009. The new rules may not be applied to disclosures in quarterly reports prior to the first annual report in which the revised disclosures are required. We are currently in the process of evaluating the new requirements.

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

We are a global integrated energy company with significant operations in the U.S., Canada, Africa and Europe. Our operations are organized into four reportable segments:

- w Exploration and Production (“E&P”) which explores for, produces and markets liquid hydrocarbons and natural gas on a worldwide basis.
- w Oil Sands Mining (“OSM”) which mines, extracts and transports bitumen from oil sands deposits in Alberta, Canada, and upgrades the bitumen to produce and market synthetic crude oil and by-products.
- w Refining, Marketing & Transportation (“RM&T”) which 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.
- w Integrated Gas (“IG”) which 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.

Certain sections of Management’s Discussion and Analysis of Financial Condition and Results of Operations include forward-looking statements concerning trends or events potentially affecting our business. These statements typically contain words such as “anticipates,” “believes,” “estimates,” “expects,” “targets,” “plans,” “projects,” “could,” “may,” “shou similar words indicating that future outcomes are uncertain. In accordance with “safe harbor” provisions of the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, which could cause future outcomes to differ materially from those set forth in forward-looking statements. For additional risk factors affecting our business, see Item 1A. Risk Factors in our 2008 Annual Report on Form 10-K.

Activities related to discontinued operations have been excluded from segment results and operating statistics.

Overview and Outlook

Exploration and Production (“E&P”)

Production

Net liquid hydrocarbon and natural gas sales averaged 436 and 415 thousand barrels of oil equivalent per day (“mboepd”) during the second quarter and first six months of 2009 compared to 347 and 357 mboepd during the second quarter and first six months of 2008. These increases over the same periods of 2008 primarily reflect the impact of a full quarter of production from the Alvheim/Vilje development offshore Norway and the Neptune development in the Gulf of Mexico compared to partial quarters in 2008 when they commenced production. For the second quarter, worldwide natural gas sales are down 5 percent, primarily in the U.S. as a result of property sales, the timing of Alaska storage activities and natural decline in Gulf of Mexico, while natural gas sales in Equatorial Guinea have increased due to improved reliability at the LNG plant which purchase this natural gas.

We have drilled all four development wells on the Droshky discovery in the Gulf of Mexico on Green Canyon Block 244. Well completions are underway and the project is on track for our first production target of 2010.

Exploration

During the second quarter 2009, we announced the Oberon discovery on Block 31 offshore Angola. We also participated in 2 exploration wells in Block 31 and are in the process of drilling another exploration well. We hold a 10 percent outside-operated interest in Block 31 and a 30 percent outside-operated interest in Block 32, pending the sale of two-thirds of our Block 32 interest as discussed below.

During the second quarter 2009, we were awarded all 16 blocks bid in the Central Gulf of Mexico Lease Sale No. 208 conducted by the Minerals Management Service. Ten blocks are 100 percent Marathon, and the remaining six blocks were bid with partners, for a total of $62 million. We have acquired a total of 59 new leases from lease sales held 2007 through 2009.

We were awarded a 49 percent interest and will serve as operator in the Kumawa Block offshore Indonesia, our third Indonesian offshore exploration block. The Kumawa Block encompasses 1.24 million acres.

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Divestitures

In April 2009, we closed the sale of our operated properties in Ireland for net proceeds of $84 million, after adjusting for cash held by the sold subsidiary. A $158 million pretax gain on the sale was recorded. Net production from these operations averaged 5,000 boepd in the first quarter of 2009. Our net proved reserves associated with these assets as of December 31, 2008, were 6 million barrels of oil equivalent ("mmboe"). As a result of this sale, we terminated our pension plan in Ireland, incurring a charge of $18 million which reduced the gain on sale.

On June 24, 2009, we entered into an agreement to sell the subsidiary holding our 19 percent outside-operated interest in the Corrib natural gas development offshore Ireland. Total proceeds will range between $235 million and $400 million, subject to the timing of first commercial gas at Corrib and closing adjustments. At closing on July 30, 2009, the initial $100 million payment plus closing adjustments was received. Additional proceeds of $135 million to $300 million will be received on the earlier of first commercial gas or December 31, 2012. The fair value of the consideration for this asset was $311 million which was less than its book value. An impairment of $154 million was recognized in the second quarter of 2009 in discontinued operations. Additional gains or losses may be recognized until the final proceeds payment is received (see Note 10).

As a result of these dispositions, our Irish exploration and production businesses have been reported as discontinued operations in the consolidated statements of income and the consolidated statements of cash flows for all periods presented. The net loss on the sales reported in discontinued operations for 2009 was $14 million before income taxes.

In July 2009, we entered into an agreement to sell an undivided 20 percent outside-operated interest in the Production Sharing Contract and Joint Operating Agreement in Block 32 offshore Angola for $1.3 billion, excluding any purchase price adjustments at closing, with an effective date of January 1, 2009. We will retain a 10 percent outside-operated interest in Block 32. We expect to close the transaction by year-end 2009, subject to government and regulatory approvals.

In June 2009, we closed the sales of a portion of our operated and all of our outside-operated Permian Basin producing assets in New Mexico and west Texas for net proceeds after closing adjustments of $292 million. A $199 million pretax gain on the sale was recorded. Net production from these operations averaged 8,150 boepd in the first quarter of 2009. Our net proved reserves associated with these assets as of December 31, 2008, were 14 mmboe.

The above discussions include forward-looking statements with respect to the timing and levels of future production, anticipated future exploratory drilling activity and pending divestitures. 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 divestitures 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 was 26 thousand barrels per day (“mbpd”) in the second quarter and 25 mbpd in the first six months of 2009.

In the second quarter of 2009, the operator of AOSP offered three additional leases to the other joint venture partners for the Muskeg River Mine. Terms of the transaction were as agreed in the original 1999 AOSP Joint Venture Agreement. We elected to participate in these leases and our net proved reserves increased 168 million barrels. These additional reserve barrels will initially reduce our depreciation, depletion and amortization (“DD&A”) rate per barrel by approximately 40 percent beginning in June 2009.

The Alberta government announced its decision to consider the proposed AOSP’s Quest carbon capture and sequestration (“CCS”) project, involving the Scotford upgrader, for possible government funding. The AOSP partners are currently working with the government on a letter of intent, after which a funding agreement will be negotiated. A final investment decision on the Quest project will be made at a later date, pending agreement on funding details with the Government of Alberta, regulatory approvals, stakeholder engagement, as well as final agreement of the joint venture partners.

The above discussion includes forward-looking statements with respect to future DD&A levels. The DD&A rate change is an estimate and actual future results may differ.

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

Our total refinery throughputs were 4 percent and 2 percent lower in the second quarter and first six months of 2009 than in the second quarter and first six months of 2008. Crude oil refined likewise decreased 6 percent and 3 percent in the same periods. The throughput declines in 2009 relate primarily to our level of planned maintenance activities. Planned major maintenance activities were completed at our Canton, Ohio; Catlettsburg, Kentucky; Robinson, Illinois, and Garyville, Louisiana, refineries in the first half of 2009. In the first and second quarters of 2008, major maintenance activities occurred at our Detroit, Michigan; Garyville and Robinson refineries.

Volumes under our ethanol blending program increased to 70 mbpd for the first six months of 2009, a 39 percent increase over the same period of 2008. For the second quarter of 2009 we blended an average of 73 mbpd, or 30 percent more ethanol than in the same period of 2008. The future expansion or contraction of our ethanol blending program will be driven by the economics of ethanol supply and government regulations.

Second quarter 2009 Speedway SuperAmerica LLC ("SSA") same store gasoline sales volume increased 3 percent when compared to the second quarter of 2008. This compares to an estimated demand decline of about 2 percent in our market area in the second quarter 2009, while same store merchandise sales increased by 14 percent for the same period.

As of July 31, 2009, the expansion of our Garyville, Louisiana refinery is 91 percent complete with an on-schedule startup expected in the fourth quarter 2009. We now forecast that the project will cost $3.7 billion, or approximately 10 percent more than our previously stated cost estimate. Delays in receipt of materials and fabricated equipment contributed to revisions in work execution plans, resulting in increased project costs. Construction activities continue on the heavy oil upgrading and expansion project at our Detroit refinery with completion expected in the last half of 2012.

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")

Our share of LNG sales worldwide totaled 6,611 metric tonnes per day ("mtpd") for the second quarter of 2009 compared to 6,402 mtpd in the second quarter of 2008 and 6,690 mtpd in the first six months of 2009 compared to 6,657 mtpd in the first six months of 2008. 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. The LNG production facility in Equatorial Guinea had operational availability of 99 percent in the second quarter of 2009.

We continue to invest in the development of new technologies to create value and supply new energy sources. In the second quarter and first six months of 2009, we recorded costs of approximately $18 and $36 million related to natural gas technology research, including our GTF™ technology. Similar spending in the same periods of 2008 was $22 million and $38 million.

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Market Conditions

Exploration and Production

Prevailing prices for the various qualities of crude oil and natural gas that we produce significantly impact our revenues and cash flows. Prices continue to be volatile in 2009, with the following table listing benchmark crude oil and natural gas price averages for the second quarter and first six months of 2009 and 2008 are listed below to illustrate the volatility:

	Three Months Ended June 30,		Six Months Ended June 30,	
Benchmark	2009	2008	2009	2008
WTI crude oil (Dollars per barrel)	$ 59.79	$ 123.80	$ 51.68	$ 111.12
Brent crude oil (Dollars per barrel)	$ 59.13	$ 121.18	$ 51.68	$ 109.05
Henry Hub natural gas (Dollars per mcf)(a)	$ 3.51	$ 10.94	$ 4.21	$ 9.49

(a) First-of-month price index.

On average, crude oil prices in 2009 were lower than in 2008. Crude oil prices declined rapidly through February 2009 from a high of over $140 per barrel in July 2008. By June 2009 prices were approximately half of the previous year’s maximum levels.

Our domestic crude oil production is on average heavier and higher in sulfur content than light sweet WTI. Heavier and higher sulfur crude oil (commonly referred to as heavy sour crude oil) typically sells at a discount to light sweet crude oil. Our international crude oil production is relatively sweet and is generally sold in relation to the Brent crude oil benchmark.

Natural gas prices on average were also lower in 2009 than in 2008. Our natural gas sales in Alaska are subject to term contracts. Our other major natural gas-producing regions are Europe and Equatorial Guinea, where large portions of our natural gas sales are subject to term contracts, making realized prices in these areas less volatile. As we sell larger quantities of natural gas from these regions, to the extent that these fixed prices are lower than prevailing prices, our reported average natural gas prices realizations may decrease.

Our worldwide E&P revenues during the second quarter and first six months of 2009 were 41 and 45 percent lower than in the same periods of 2008, with the majority of the revenue decreases tied to these decreases in average commodity prices.

Oil Sands Mining

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

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

The table below shows benchmark prices that impacted both our revenues and variable costs for the second quarter and first six months of 2009 and 2008:

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	Three Months Ended June 30,		Six Months Ended June 30,	
Benchmark	2009	2008	2009	2008
WTI crude oil (Dollars per barrel)	$ 59.79	$ 123.80	$ 51.68	$ 111.12
Western Canadian Select (Dollars per barrel)(a)	$ 52.36	$ 102.18	$ 43.50	$ 89.58
AECO natural gas sales index (Canadian dollars per gigajoule)(b)	$ 3.28	$ 9.67	$ 4.00	$ 8.56

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

(b) Alberta Energy Company day ahead index.

Excluding the impact of derivatives, our OSM segment revenues for the second quarter and first six months of 2009 were lower than for the same periods of 2008, reflecting the impact of lower price realizations for synthetic crude oil and vacuum gas oil sales. Realizations were 53 percent lower in the second quarter and 55 percent lower for the first six months of 2009, compared to the same periods of 2008.

Refining, Marketing and Transportation

RM&T segment income depends largely on our refining and wholesale marketing gross margin, refinery throughputs, retail marketing gross margins for gasoline, distillates and merchandise, and the profitability of our pipeline transportation operations.

Our refining and wholesale marketing gross margin is the difference between the prices of refined products sold and the costs of crude oil and other charge and blendstocks refined, including the costs to transport these inputs to our refineries, the costs of purchased products and manufacturing expenses, including depreciation. The crack spread is a measure of the difference between spot market prices at major trading locations for refined products and crude oil, commonly used by the industry as an indicator of the impact of price on the refining margin. Crack spreads can fluctuate significantly, particularly when prices of refined products do not move in the same relationship as the cost of crude oil. As a performance benchmark and a comparison with other industry participants, we calculate Midwest (Chicago) and U.S. Gulf Coast crack spreads that we feel most closely track our operations and slate of products. Posted Light Louisiana Sweet ("LLS") prices and a 6-3-2-1 ratio of products (6 barrels of crude oil refined into 3 barrels of gasoline, 2 barrels of distillate and 1 barrel of residual fuel) are used for the crack spread calculation. The following table lists calculated average crack spreads for the Midwest and Gulf Coast markets and the sweet/sour differential for the second quarter and first six months of 2009 and 2008:

	Three Months Ended June 30,		Six Months Ended June 30,	
(Dollars per barrel)	2009	2008	2009	2008
Chicago LLS 6-3-2-1 crack spread	$ 5.73	$ 2.71	$ 4.34	$ 1.42
U.S. Gulf Coast LLS 6-3-2-1 crack spread	$ 3.59	$ 1.99	$ 3.25	$ 1.70
Sweet/Sour differential(a)	$ 3.98	$ 13.74	$ 5.60	$ 13.31

(a)

Calculated using the following mix of crude types: 15% Arab Light, 20% Kuwait, 10% Maya, 15% Western Canadian Select, 40% Mars.

In addition to the market changes indicated by the crack spreads, our refining and wholesale marketing gross margin is impacted by factors such as:

- the types of crude oil and other charge and blendstocks processed,
- the selling prices realized for refined products,
- the impact of commodity derivative instruments used to manage price risk,
- the cost of products purchased for resale, and
- changes in manufacturing costs, which include depreciation.

Our refineries can process significant amounts of sour crude oil which may enhance our margin compared to what the change in the relevant crack spread indicators would suggest, as sour crude oil typically can be purchased at a discount to sweet crude oil. The amount of this discount can and does vary significantly and can therefore have a significant impact on our refining and wholesale marketing gross margin. Manufacturing costs are primarily driven by the cost of energy used by our refineries and the level of maintenance activities.

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Our refining and wholesale marketing gross margin for the second quarter and first six months of 2009 was higher when compared to the same periods of 2008, as anticipated based upon the improvement in crack spreads, but the significantly unfavorable sweet/sour differential offset most of the favorable crack spread impact.

Integrated Gas

Our integrated gas strategy is to link stranded natural gas resources with areas where a supply gap is emerging due to declining production and growing demand. Our integrated gas operations include marketing and transportation of products manufactured from natural gas, such as LNG and methanol, primarily in the U.S., Europe and West Africa.

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

We own a 45 percent interest in a methanol plant located in Equatorial Guinea through our investment in Atlantic Methanol Production Company LLC (“AMPCO”). Methanol demand has a direct impact on AMPCO’s earnings. Because global demand for methanol is rather limited, changes in the supply-demand balance can have a significant impact on sales prices. AMPCO’s plant capacity is 1.1 million tonnes, or 3 percent of 2008 world demand. Also included in the financial results of the Integrated Gas segment are costs associated with ongoing development of integrated gas projects, including natural gas technology research.

The impact of lower Henry Hub prices in the second quarter and first six months of 2009 compared to the same periods of 2008 can be seen in decreased earnings from the LNG production facility although the production levels increased over the same periods. Our methanol realizations were also down during the second quarter. This was in line with methanol prices in the U.S. and European markets that averaged approximately $200 per metric tonne in the second quarter of 2009, down from approximately $485 per metric tonne in the same quarter of 2008.

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 June 30,		Six Months Ended June 30,	
(In millions)	2009	2008	2009	2008
E&P	$ 2,008	$ 3,401	$ 3,446	$ 6,314
OSM	155	16	277	215
RM&T	11,067	18,975	19,741	34,001
IG	7	21	18	40

Segment revenues		13,237		22,413		23,482		40,570
Elimination of intersegment revenues		(160)		(359)		(313)		(703)
Gain (loss) on U.K. natural gas contracts		3		(165)		85		(235)
Total revenues	$	13,080	$	21,889	$	23,254	$	39,632
Items included in both revenues and costs:								
Consumer excise taxes on petroleum products and merchandise	$	1,226	$	1,295	$	2,400	$	2,511

E&P segment revenues decreased $1,393 million in the second quarter and $2,868 million in the first six months of 2009 from the comparable prior-year periods. The decrease was primarily a result of lower liquid hydrocarbon and natural gas price realizations. Liquid hydrocarbon realizations averaged $55.49 per barrel in the second quarter and $48.70 in the first six months of 2009 compared to $111.90 and $100.07 in the same periods of 2008, while natural gas realizations averaged $2.19 per mcf in the second quarter and $2.51 in the first six months of 2009 compared to $5.08 and $4.79 in the same periods of 2008.

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Net sales volumes during the quarter averaged 436 mboepd, compared to 347 mboepd for the same period last year. This 26 percent increase in sales volumes partially offsets the liquid hydrocarbon and natural gas realization decreases previously discussed. Net sales volumes for the first six months of 2009 were 16 percent higher than the comparable prior-year period.

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

Excluded from E&P segment revenues were gains of $3 million and losses of $165 million for the second quarters of 2009 and 2008 related to natural gas sales contracts in the U.K. that are accounted for as derivative instruments. For the first six months of 2009 and 2008 gains of $85 million and losses of $235 million are excluded from E&P segment revenues.

OSM segment revenues increased $139 million in the second quarter and $62 million in the first six months of 2009 compared to the same periods of 2008, reflecting the impact of the options we entered in the first quarter of 2009 which effectively offset the open put options for the remainder of 2009. The impact of derivatives in 2009 was insignificant compared to pretax derivative losses of $338 million and $386 million in the second quarter and first six months of 2008. Net synthetic crude sales for the second quarter of 2009 were 30 mbpd at an average realized price of $55.02 per barrel compared to 31 mbpd at an average realized price of $116.40 in the same period last year.

See Note 11 to the consolidated financial statements for additional information about derivative instruments.

RM&T segment revenues decreased $7,908 million in the second quarter of 2009 and $14,260 million in the first six months of 2009 from the comparable prior-year periods. The second quarter and the six month decreases compared to prior year primarily reflect lower refined product selling prices.

Sales to related parties decreased as a result of the sale of our interest in Pilot Travel Centers LLC ("PTC") during the fourth quarter of 2008.

Income from equity method investments decreased $194 million in the second quarter of 2009 and $356 million in the first six months of 2009 from the comparable prior-year periods. Lower commodity prices negatively impacted the earnings of many of our equity investees. The sale of our equity method investment in PTC during the fourth quarter of 2008 also contributed to the decrease.

Net gain on disposal of assets in the second quarter and first six months of 2009 primarily represents the sale of a portion of our operated and all of our outside-operated Permian Basin producing assets in New Mexico and west Texas.

Cost of revenues decreased $8,209 million and $15,267 million in the second quarter and first six months of 2009 from the comparable prior-year periods. These decreases resulted primarily from decreases in acquisition costs of crude oil, refinery charge and blendstocks and purchased refined products in the RM&T segment.

Depreciation, depletion and amortization increased in the second quarter and first six months of 2009 from the comparable prior-year periods. The DD&A increase is primarily due to the commencement of production from the Alvheim/Vilje and Neptune developments in mid-year 2008.

Selling, general and administrative expenses decreased in the second quarter and first six months of 2009 from the comparable prior-year periods primarily due to lower variable compensation expenses.

Exploration expenses were $64 million and $126 million in the second quarter and first six months of 2009, including expenses related to dry wells of $8 million and $12 million. Exploration expenses were $130 million and $259 million in the second quarter and first six months of 2008, including expenses related to dry wells of $52 million and $82 million. Other exploration expense in the first six months of 2008 related to the acquisition of seismic data in Indonesia and the evaluation of Canadian in-situ oil sands leases.

Provision for income taxes decreased $95 million and $395 million in the second quarter and first six months of 2009 from the comparable periods of 2008 as a result of decreases in income before income taxes. The effective tax rate is influenced by a variety of factors including the geographic and functional sources of income and the relative magnitude of these sources of income. The change in mix of liquid hydrocarbon and natural gas sales in 2009 from 2008 included more sales in jurisdictions with high tax rates. This change, as well as unfavorable foreign currency remeasurement effects, contributed to the increase in the effective income tax rate in the second quarter and first six months of 2009 as compared to the same periods in 2008. The following is an analysis of the effective income tax rates for the first six months of 2009 and 2008:

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	Six Months Ended June 30,	
	2009	2008
Statutory U.S. income tax rate	35%	35%
Foreign taxes in excess of federal statutory rate	25	14
State and local income taxes, net of federal income tax effects	1	1
Other tax effects	-	(2)
Effective income tax rate	61%	48%

Discontinued operations reflect the impact of the disposal of our E&P businesses in Ireland to date (see Note 4) and the historical results of those operations, net of tax, for all periods presented.

Segment Results

Segment income is summarized in the following table:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2009	2008	2009	2008
E&P				
United States	$ (41)	$ 359	$ (93)	$ 603
International	261	463	398	891
E&P segment	220	822	305	1,494
OSM	2	(157)	(22)	(130)
RM&T	165	158	324	83
IG	13	102	40	201
Segment income	400	925	647	1,648
Items not allocated to segments, net of income taxes:				
Corporate and other unallocated items	(89)	(57)	(140)	(78)
Foreign currency remeasurement of deferred taxes	(94)	(16)	(66)	35
Gain on dispositions	122	-	122	-
Gain (loss) on U.K. natural gas contracts	2	(84)	44	(120)
Discontinued operations	72	6	88	20
Net income	$ 413	$ 774	$ 695	$ 1,505

United States E&P income decreased $400 million and $696 million in the second quarter and first six months of 2009 compared to the same periods of 2008. Revenues decreased approximately 60 percent in the second quarter and 58 percent in the first six months of 2009, primarily as a result of lower realizations on both liquid hydrocarbons and natural gas. Liquid hydrocarbon sales volumes were higher in both periods due to sales from the Neptune development. The benefit was offset by the DD&A impact of Neptune production, which was $90 million in the second quarter and $142 million in the first six months of 2009. In the first quarter of 2009, proved reserves for Neptune were revised downward, increasing the DD&A per barrel. Other expenses totaling $28 million in the second quarter of 2009 and $65 million for the six-month period included rig cancellation fees and partial impairment of a natural gas field in east Texas and a Gulf of Mexico pipeline investment.

International E&P income decreased $202 million and $493 million in the second quarter and first six months of 2009 compared to the same periods of 2008. The decrease was primarily due to approximately 50 percent lower liquid hydrocarbon realizations for the second quarter and first six months of 2009 compared to the same periods of 2008. Liquid hydrocarbon sales from the Alvheim/Vilje development which commenced production in June 2008 had a favorable income impact, partially offset by the DD&A related to its production. Lower exploration expenses had a positive income impact.

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OSM segment income increased $159 million and $108 million in the second quarter and first six months of 2009. After-tax derivative losses of $250 million and $286 million were included in reported income for the second quarter and first six months of 2008. Derivative gains or losses in 2009 were not significant. Exclusive of the derivative effects, OSM segment income would reflect decreases in both periods driven by lower synthetic crude realizations, partially offset by lower energy and feedstock costs.

RM&T segment income increased by $7 million and $241 million in the second quarter and first six months of 2009 compared to the same periods of 2008. The increase in the six-month period was primarily due to improvement in our refining and wholesale marketing gross margin which averaged 8.71 cents per gallon in the second quarter of 2009 and 8.33 cents per gallon in the first six months of 2009 compared to 8.35 cents per gallon and 4.2 cents per gallon in the comparable periods of 2008. The gross margin increase was primarily due to improved crack spreads as reflected in the relevant market indicators [Light Louisiana Sweet (LLS) 6-3-2-1 crack spreads] in the Midwest (Chicago) and Gulf Coast, and lower manufacturing expenses in the second quarter 2009 compared to the same quarter last year. The lower manufacturing expenses resulted primarily from lower energy costs. However, these favorable impacts were largely offset by a relatively higher cost of crude oil, primarily driven by a substantially narrower sweet/sour differential, and other feedstock costs, compared to the average prices reflected in the market indicators.

Our refining and wholesale marketing gross margin also included pretax derivative gains of $13 million and losses of $47 million in the second quarter and first six months of 2009 compared to losses of $187 million and $307 million in the second quarter and first six months of 2008.

SSA's product and merchandise margin improved $29 million in the second quarter and $36 million in the first six months of 2009 compared to the same periods of 2008, reflecting both increases in our retail light products margin per gallon and total sales volumes year over year.

IG segment income decreased $89 million in the second quarter of 2009 and $161 million in the first six months of 2009 compared to the same periods of 2008. The decrease was primarily the result of lower price realizations.

Management's Discussion and Analysis of Cash Flows and Liquidity

Cash Flows

Net cash provided by operating activities totaled $1,750 million in the first six months of 2009, compared to $2,955 million in the first six months of 2008. Cash provided by operating activities decreased primarily due to lower net income. Working capital changes decreased net cash provided by