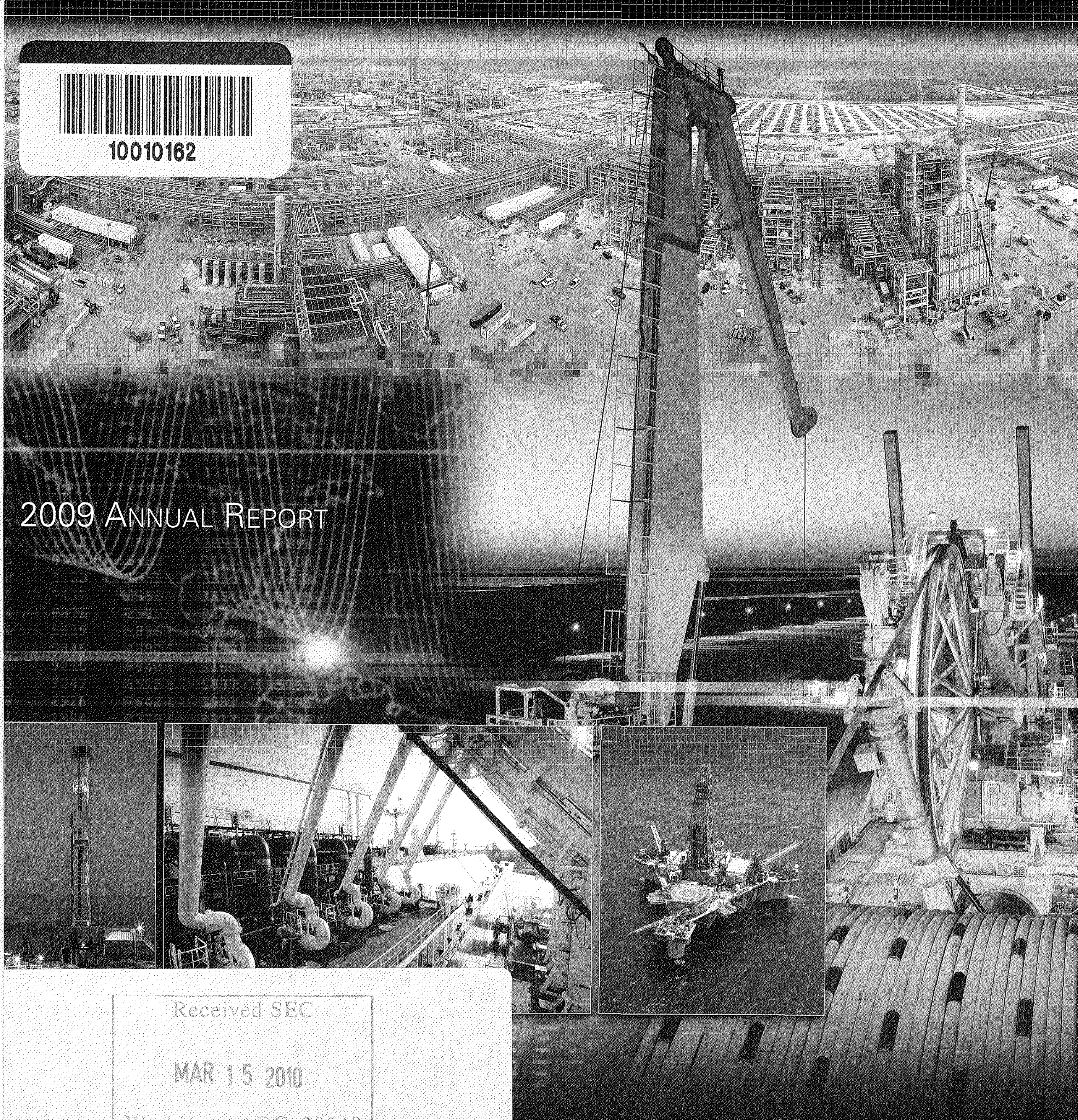
2009 Annual Report



Marathon

Financial Highlights

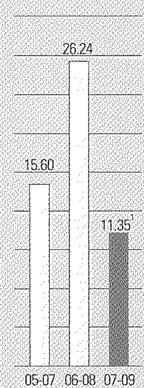
Dollars in millions, except where noted	2009	2008[a]	2007[a]
Revenues	$ 53,470	$ 76,754	$ 64,096
Income from operations	3,590	6,779	6,370
Income from continuing operations	1,184	3,384	3,766
Net income	1,463	3,528	3,956
Per common share data (in dollars)[b]			
Income from continuing operations – basic	$ 1.67	$ 4.77	$ 5.46
Net income – basic	$ 2.06	$ 4.97	$ 5.73
Income from continuing operations – diluted	$ 1.67	$ 4.75	$ 5.42
Net income – diluted	$ 2.06	$ 4.95	$ 5.69
Dividends	$ 0.96	$ 0.96	$ 0.92
Average shares outstanding – diluted (in millions)[b]	711	713	695
Cash and cash equivalents[c]	2,057	1,285	1,199
Long-term debt[c]	8,436	7,087	6,084
Stockholders' equity[c]	21,910	21,409	19,223
Total assets[c]	47,052	42,686	42,746
Net cash from operating activities (from continuing operations)	5,210	6,533	5,671
Capital expenditures[d] [e]	5,891	7,004	4,381
Average daily net sales:[e]			
Exploration and Production Segment			
Liquid hydrocarbons (mbpd)	243	205	186
Natural gas (mmcfd)[f]	941	979	886
Barrels of oil equivalent (mboepd)	400	369	334
Oil Sands Mining Segment			
Synthetic crude oil (mbpd)[g]	32	32	4
Integrated Gas Segment			
Liquefied natural gas (mtpd)	6,642	6,285	3,310
Methanol (mtpd)	1,192	975	1,308
Annual net sales:[e]			
Exploration and Production Segment			
Liquid hydrocarbons (mmbbl)	89	75	68
Natural gas (bcf)[h]	344	357	323
Barrels of oil equivalent (mmboe)	146	135	122
Oil Sands Mining Segment			
Synthetic crude oil (mmbbl)	12	12	2
Integrated Gas Segment			
Liquefied natural gas (thousand metric tonnes)	2,424	2,300	1,208
Methanol (thousand metric tonnes)	435	357	477
Net proved reserves:[c]			
Oil and Gas Producing Activities			
Liquid hydrocarbons (mmbbl)	622	636	650
Synthetic crude oil (mmbbl)[i]	603	n/a	n/a
Natural gas (bcf)	2,724	3,351	3,450
Barrels of oil equivalent (mmboe)	1,679	1,195	1,225
Oil Sands Mining Segment			
Bitumen (mmbbl)[i]	n/a	388	421
Refinery operations:			
Refinery runs – crude oil refined (mbpd)	957	944	1,010
Refinery runs – other charge and blend stocks (mbpd)	196	207	214
Consolidated refined product sales (mbpd):[j]	1,378	1,352	1,410
Speedway SuperAmerica LLC:			
Gasoline and distillate sales (million gallons)	3,232	3,215	3,356
Merchandise sales	$ 3,109	$ 2,838	$ 2,796
Number of retail marketing outlets:[c]			
Marathon Brand	4,613	4,577	4,444
Speedway SuperAmerica LLC	1,603	1,617	1,636
Number of employees[c]	28,855	30,360	29,524

(a) Our businesses in Ireland and Gabon were sold in 2009. All periods have been recast to reflect these businesses as discontinued operations. (b) Share and per share information has been restated for two-for-one stock split effected June 18, 2007, in the form of a stock dividend. (c) As of end of period presented. (d) Excludes acquisitions and includes accruals. (e) Excludes discontinued operations. (f) Includes natural gas acquired for injection and subsequent resale of 22, 32 and 47 mmcfd in the years ended December 31, 2009, 2008 and 2007, respectively. (g) The Oil Sands Mining operations were acquired October 18, 2007. Daily volumes reported in 2007 represent activity after the acquisition date divided by the total number of days in a year. (h) Includes natural gas acquired for injection and subsequent resale of 8, 12 and 17 bcf in the years ended December 31, 2009, 2008 and 2007, respectively. (i) Under new Securities and Exchange Commission regulations, beginning December 31, 2009, oil sands mining is included in oil and gas producing activities and the related reserves are reported as synthetic crude oil. (j) Total average daily volume of all refined product sales to wholesale, branded and retail (Speedway SuperAmerica LLC) customers.

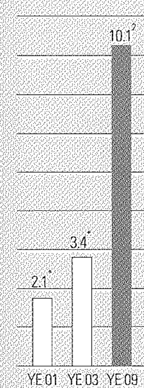
bcf	billion cubic feet	mmbbl	million barrels	mmcfd	million cubic feet per day
mboepd	thousand barrels of oil equivalent per day	mmboe	million barrels of oil equivalent	mtpd	metric tonnes per day
mbpd	thousand barrels per day				

Operational Highlights

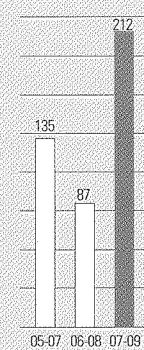
Finding and Development Cost
Three-Year Rolling Average in Dollars per BOE



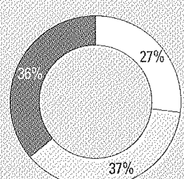
Total Resource
Billions of BOE



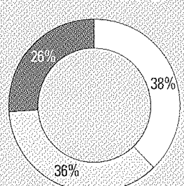
Reserve Replacement[3]
Three-Year Rolling Average in Percent

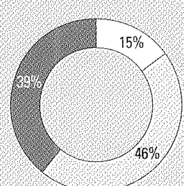


2009 Production Mix[2]
North America Europe Africa

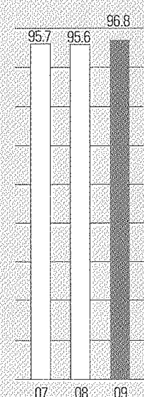


Liquids Recorded Sales
Gas Recorded Sales
U.S. Europe Africa

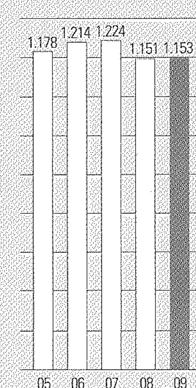




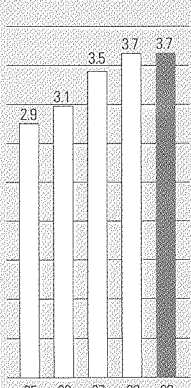
Downstream Mechanical Availability
Percentage of Combined Unit Capacity



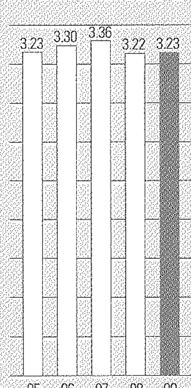
Total Refinery Throughputs
Millions of Barrels Per Day



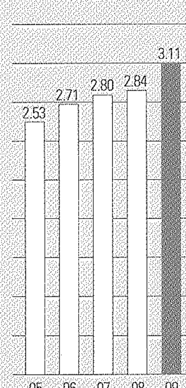
Marathon Brand Gasoline and Distillate Sales
Billion Gallons



Speedway SuperAmerica Light Product Sales
Billions of Gallons



Speedway SuperAmerica Merchandise Sales
Billions of Dollars



1 The three-year period includes $1 billion for synthetic crude oil (for 2009 costs only)
2 Includes oil sands mining and in-situ volumes 3 Excluding dispositions * Total Mean Resource

Dear Fellow Shareholders

Against the backdrop of a significant global economic downturn, Marathon delivered on our commitments to profitably grow our Upstream business and to enhance our industry-leading domestic Downstream business. We continue to cost-effectively execute on major projects and other investments that will sustain profitable growth beyond 2012. Our employees, business plans and assets proved up to the challenges presented by volatile commodity prices and margins, as well as the significant uncertainty from the unusual economic conditions seen over the past year.

Clarence P. Cazalot Jr.
President and Chief Executive Officer

Thomas J. Usher
Chairman of the Board

Our proven record of performance has positioned Marathon for sustainable, profitable growth.

Upstream (exploration and production, oil sands mining and integrated gas) provides profitable production growth and an expanding global portfolio that offers repeatable exploration and production successes. We have increased production at a compound average growth rate of 5 percent since 2004, while selling approximately 100 million barrels of proved reserves and 60 thousand barrels of oil equivalent per day (mboepd) of production during this growth period. In the Exploration and Production segment, production available for sale in 2009 (excluding discontinued operations) was 405 mboepd, a 9 percent increase from 2008 primarily driven by higher production in Norway and Equatorial Guinea.

Through well-executed exploration programs and selective acquisitions, Marathon has tripled the size of our resource base since 2001. We have a proved reserve base of approximately 1.7 billion barrels of oil equivalent (bboe), with a current reserves-to-production ratio greater than 10 years.

Exploration and Production segment cost per barrel was a competitive $24.02, a 6 percent reduction from 2008. Exercising strict control over capital and operating expenses and dramatically improving reliability in major operated assets contributed to our advantageous cost structure, a differentiator for Marathon.

In Downstream (refining, marketing and transportation), a highly integrated asset system, flexibility and sharp commercial skills enable Marathon to capitalize on changing crude and feedstock economics, global refined products demand and emerging renewable fuels and biofuels. Our Downstream assets enjoy attractive economies of scale that reduce capital expenditures and optimize capacity.

In 2009, Downstream maintained its top-tier U.S. ranking with adjusted income from operations per barrel of crude oil throughput of $2.00. Our seven refineries ran an average of 957 thousand barrels per day (mbpd) of crude oil and 1,153 mbpd of total refinery throughput. In addition, we achieved strong Downstream mechanical availability of 96.8 percent.

Safety is a key value and performance indicator for Marathon, and we believe that continuous improvement in safety will yield ongoing operational excellence. Through planning, focus, awareness, adaptability and committed teamwork among employees and contractors, safety performance improved compared to 2008. Unfortunately, we had three fatalities involving contractors in separate incidents in Equatorial Guinea and Louisiana in 2009 and one employee fatality in West Virginia in January 2010. No injury or loss of life is acceptable and we have sharpened our focus on safety to ensure that similar incidents do not occur again. We will not be satisfied until every Marathon employee and contractor goes home safely every day.

Over the past three years, Marathon has invested substantially in major projects that we expect to generate significant positive cash flows for many years to come.

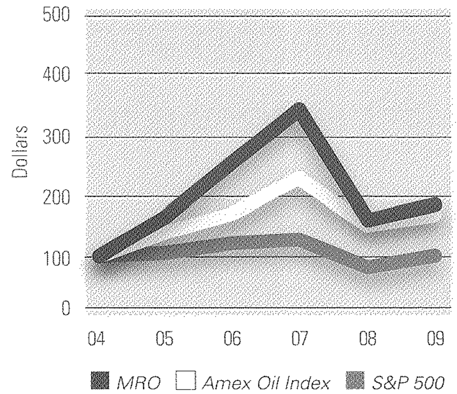
In its first full year of operation, our Alvheim/Vilje Development Area in Norway already has exceeded this expectation. The on-time completion of the Garyville Major Expansion (GME) at year-end 2009 positions our largest refining asset to benefit from an economic recovery.

The deepwater Droshky project in the Gulf of Mexico is a rapidly paced field development that exemplifies our ability to execute safe, competitive, predictive projects that create meaningful value for the Company. In our Canadian oil sands business, the Athabasca Oil Sands Project (AOSP) Expansion 1 is anticipated to begin mining operations the second half of 2010, and upgrading operations in late 2010 or early 2011.

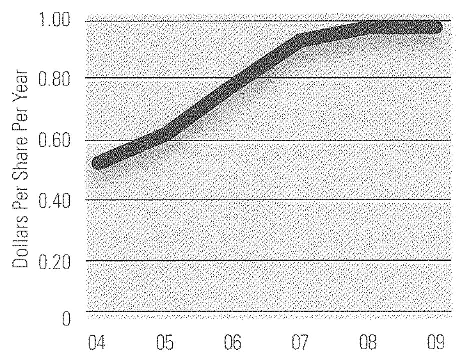
With GME now operating and AOSP Expansion 1 and Droshky nearing completion, Marathon's $5.1 billion 2010 capital budget is 17 percent lower than our 2009 budget. We will target future spending levels to be linked with expected cash flow generation. We will direct more of our expenditures to Upstream growth opportunities – notably deepwater exploration in the Gulf of Mexico and Indonesia, global resource plays and deepwater development in Angola – while holding finding and development costs to a competitive $20-$25 per barrel. Downstream capital spending is aimed at maintaining our position as an industry leader. Our refining, marketing and transportation businesses are expected to generate competitive returns and provide substantial cash flow back to Marathon.

Cumulative Total Return

Return on $100 invested on December 31, 2004



Dividend History*



**Restated for two-for-one stock split.*

Even as we advanced and completed large-scale growth projects, Marathon maintained our solid financial position, enhanced shareholder value and delivered a competitive dividend. Cost control has been a hallmark of our management. We continue to maintain a top quartile operating expense per boe in our E&P segment, have held refining operating costs below the U.S. competitor average for 2002-2008 and reduced Speedway SuperAmerica's (SSA) light product breakeven margin by 39 percent from 2003-2009. General and Administrative costs remained flat and production increased, resulting in a declining per unit cost. We continue to push for lower costs across all our segments, as well as at the Corporate level.

The Company strives for financial flexibility both to maintain current operations and to take advantage of opportunities that arise. Marathon's net debt-to-capital ratio of approximately 23 percent and ample liquidity give us this flexibility. We had $2.1 billion in cash and cash equivalents on our balance sheet at year-end 2009 and received $1.3 billion in proceeds from asset sales closed in February 2010. We have a $3 billion bank revolver available, most of which matures in 2012-2013, and no significant debt retirements until 2012.

Our priority is to invest in value-accretive projects for Upstream, primarily through cash flow from operations and ongoing portfolio optimization. Selling mature and non-strategic assets allows Marathon to better balance our portfolio by capturing value and redeploying capital into regions with greater growth potential. We reached $3.5 billion in asset sales from our 2008 announced plan targeting asset sales of $2 to $4 billion. This includes the sale in 2009 and early 2010 of Upstream assets and interests in Ireland, Gabon, the Permian Basin in West Texas and New Mexico, and a 20 percent interest in Angola Block 32. We continue to review asset moves that enhance our portfolio, returns and shareholder value.

Marathon emphasizes dividends as a critical part of total shareholder returns. Our dividends, which reached a competitive 3 percent in 2009, have increased at more than a 12 percent compound average rate in the last five years. And while our total shareholder return for 2006-2009 was negative, our team is taking action to return Marathon to the top quartile of performance.

After investing substantially to build up a significant resource base, Marathon is poised to benefit from increased Upstream production and Downstream flexibility. We have a diversified asset base, financial and technical strength, high-impact Upstream and Downstream projects, competitive dividends and strategies to address the energy security and climate change issues facing our industry and society.

During a difficult year that severely challenged the global economy and our industry, more than 28,000 Marathon employees worldwide delivered on commitments to our investors, business partners, communities and other stakeholders. We are proud of their dedication and confident in our shared ability to sustain Marathon's growth and profitability.

Respectfully,

Thomas J. Usher
Chairman

Clarence P. Cazalot Jr.
President and Chief Executive Officer

March 2010

BUILDING A MORE SUSTAINABLE BUSINESS REQUIRES WISE INVESTMENT, ADVANCED TECHNOLOGY AND STEWARDSHIP OF THE ENVIRONMENT.

The ability to meet society's needs for energy and desires for limiting environmental impacts has emerged as a deciding factor in building a strong and viable energy business. Amid projections that global demand for oil and gas will continue to increase to 2030, the oil and gas industry and individual companies must seek a new balance: Deliver more energy with lower emissions, while maintaining economic growth and stability that provides for increased prosperity, particularly in the developing world.

Environmental and energy issues focused on climate change are shaping global economies and profoundly influencing the energy industry and its future. Major questions affecting business profitability – including the potential for higher taxes, additional regulations and access to energy resources – have yet to be answered. Given these realities, investors, business partners, governments, communities and other stakeholders have an interest in the way Marathon will manage our business in this dynamic environment.

Marathon is building a lasting enterprise through wise investments in our asset base, continued prudent financial management, development of a highly skilled workforce and environmental stewardship. To address issues that affect our long-term viability, Marathon applies our values, initiative, collaborative style and fact-based, businesslike approach to develop mutually beneficial solutions.

Marathon's size will continue to be an advantage as we plan for the future. Our company is large enough to support the skill sets, technology capabilities and complex projects of a major E&P company, but with the flexibility and speed of an independent producer. We are improving our ability to identify, screen, acquire and manage new opportunities through all phases of development.

MARATHON HAS A 123-YEAR-LONG TRACK RECORD OF EXCELLENCE IN IDENTIFYING AND CAPTURING RESOURCES AND OPERATING SUCCESSFULLY.

We have assembled a strong, diversified asset base specifically to grow production and resources profitably and responsibly, and have redeployed capital from non-strategic assets into opportunities that create greater value.

Company assets are global and distributed between Upstream and Downstream, oil and gas, conventional and unconventional, legacy and emerging, and among Organization for Economic Co-operation and Development (OECD) and non-OECD countries. Our portfolio provides the flexibility to make investment decisions around product markets and timing. The Company's resource life is nearly 60 years.

Marathon has built this high-quality portfolio to have appropriate scale, with major projects and exploration successes capable of driving impact value for shareholders. We select projects and new ventures where we can apply our proven skill sets and competencies, and act quickly on opportunities and decisions.

SUSTAINABILITY REQUIRES THE FINANCIAL CAPACITY TO INVEST IN THE FUTURE, FUND GROWTH, MAINTAIN CURRENT ASSETS AND CREATE SHAREHOLDER VALUE.

Marathon's priority is to invest in a disciplined manner in projects with value growth potential, while reducing capital, and operating and overhead costs. These efforts have been successful, notably in the financial performance of our Downstream business and development of Upstream projects.

SHARP TECHNICAL AND COMMERCIAL SKILLS AND ADVANCED TECHNOLOGY CAPABILITIES GIVE MARATHON A COMPETITIVE ADVANTAGE IN DELIVERING PROJECTS ON TIME AND ON BUDGET.

We focus on technical skills and technology around exploration, unconventional resources, enhanced oil recovery and major project execution to meet our long-term goals.

Recent Upstream projects showcase our technical skills and their long-term impact on the business. In the deepwater Droshky project in the Gulf of Mexico, high quality seismic imaging and enhanced reservoir characterization optimized the exploration phase. Lessons learned on Droshky are transferable to Marathon's future Gulf of Mexico exploration. In the North Dakota Bakken Shale, we dramatically increased drilling efficiency to reduce environmental impact and lower costs. This leadership has afforded us early access to opportunities in other areas.

Marathon brought our strengths in major project execution, commercial know-how, and crude oil and refined product markets and infrastructure to the Garyville Major Expansion. One of the most efficient refineries in the U.S., Garyville leverages the Company's integrated refining, marketing and transportation system for outstanding end-to-end flexibility and profitability.

MARATHON STRIVES TO REDUCE OUR ENVIRONMENTAL IMPACTS, WHILE EXPANDING OPERATIONS TO MEET GROWING ENERGY DEMAND.

Specific programs are aimed at decreasing use of natural resources, reducing emissions through energy efficiency improvements and investing in new technologies and renewable energy resources.

While U.S. government approaches to climate change have not been finalized, Marathon is taking steps to manage our carbon exposure and set operational energy efficiency targets. In 2009, we appointed a director of climate change and carbon management who reports to the president and CEO and oversees our climate change strategies.

Climate change also presents opportunities. We are moving forward selectively in biofuels and participating in research, and carbon capture and sequestration (CCS) projects, one of the primary carbon emissions mitigation methods.

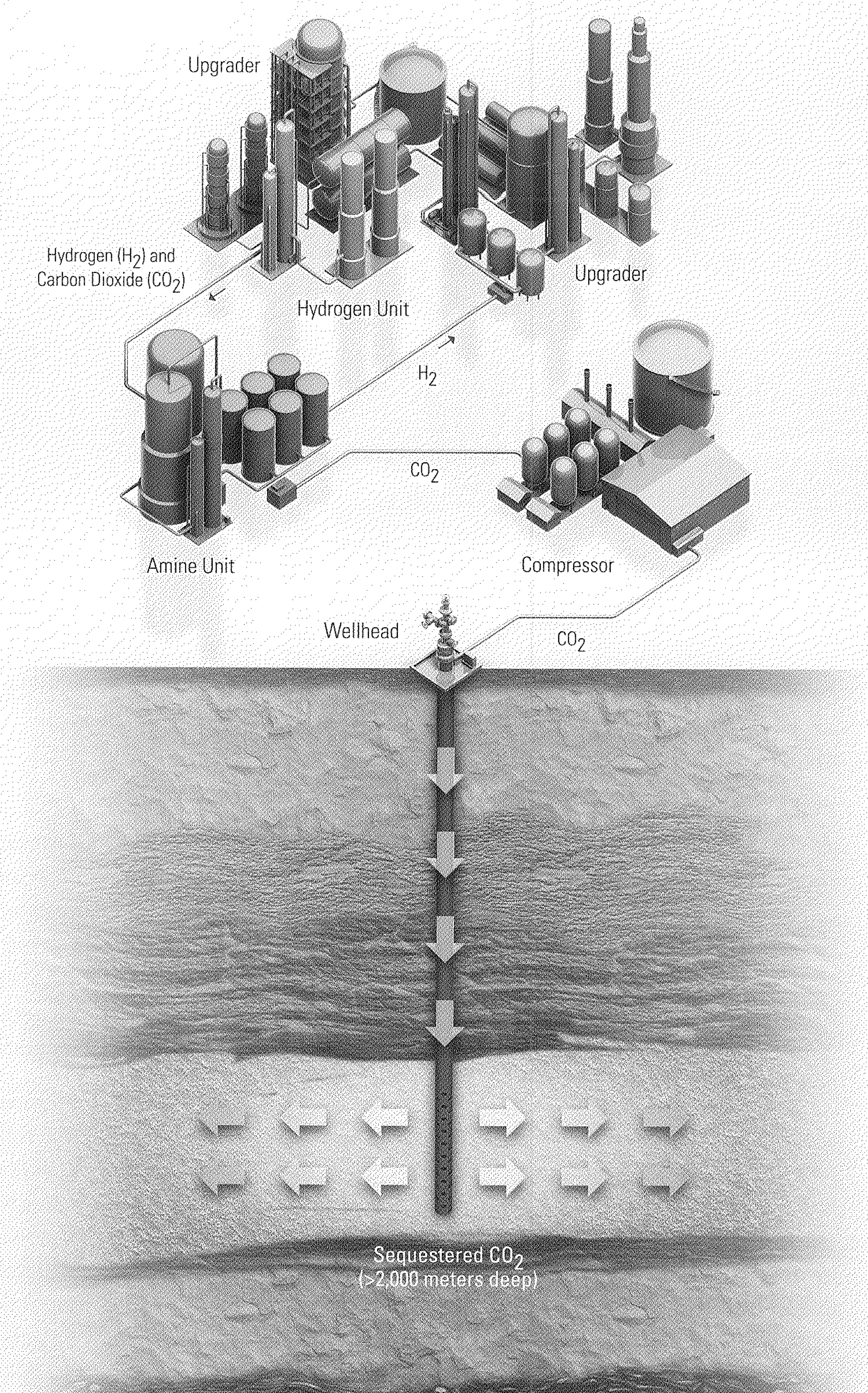
Ultimately, sustainability means adapting to change. Marathon recognizes the need to transform over time into a more broad-based energy company. We are exploring the potential of emerging technologies that enable us to adapt and thrive as we help meet both future energy needs and society's desire for cleaner energy.

We are committed to corporate social responsibility.

Marathon's corporate social responsibility (CSR) initiatives are aimed at improving the quality of life in communities where we have operations and making a positive difference, even if Marathon later leaves the area. CSR efforts are designed to support Marathon's business goals and address stakeholders' needs and expectations.

Yet, environmental, health and socioeconomic challenges that were once local, national or regional in scope now have consequences on a global scale. Marathon believes that companies, governments, non-governmental organizations and others must take a long-term, strategic view of the challenges we face and work together to address them. To this end, Marathon is actively engaged with our stakeholders to achieve sustainable solutions.

Carbon Capture and Sequestration



Marathon is a participant in a Canadian oil sands technology effort to reduce greenhouse gas emissions. The Quest CCS project involves capturing carbon dioxide (CO_2) and storing it in a deep saline aquifer with capacity of 1.1 million tonnes per year. If Quest goes forward, Marathon and our partners will be at the leading edge of technology for commercial scale CCS projects. Several important steps must be taken before a final capital investment decision is made. Considerations include the outcome of stakeholder engagement, results of appraisal activities and detailed integrated studies, and the ability to meet all regulatory requirements.

SAFE, COMPETITIVE, PREDICTIVE EXPLORATION PROJECTS ARE BUILDING BLOCKS FOR SUSTAINABILITY.

Well-executed exploration programs have been a key element in rebuilding Marathon's portfolio. The Company has a deep inventory of prospects and a balanced exploration program of new field wildcats, satellite tiebacks and onshore resource opportunities for 2010. Worldwide, up to 50 wells targeting future growth are planned, primarily in deepwater and onshore unconventional plays.

Marathon has a competitive edge due to its technical strengths, particularly internal capabilities in seismic imaging, reservoir characterization, and drilling and completion. By assessing exploration risk at a basin level, Marathon can concentrate on the highest value assets with significant resource potential, making exploration outcomes more predictive.

The Company's systematic approach to exploration starts with identifying the highest resource density in select trends and plays where it can apply its integrated work program to achieve a lead position. Marathon looks for opportunities to use its proven skill set for repeatable exploration successes.

In the Gulf of Mexico, Marathon's strong new prospect inventory is approximately 1.2 billion barrels of oil equivalent (bboe) unrisked resource potential net to Marathon. Rigs are contracted for three new operated wildcat wells in established Miocene sub-basins. Marathon also will participate in one non-operated exploration well and up to three non-operated appraisal wells.

Offshore Indonesia, Marathon is the operator of approximately 3.5 million acres across three blocks. All have multiple play types and multiple large prospects. Two high-risk, high-reward wells in the Pasangkayu Block are planned in 2010, representing approximately 1 bboe gross unrisked potential. In 2009, Marathon drilled the Marihøne A and Viper discovery wells near its Alvheim development offshore Norway. Drilling rigs are secured to drill three to four Alvheim satellite prospects in 2010, targeting first production in 2013-2014.

In deepwater Angola, the Company and its partners have announced 31 discoveries and anticipate first oil from the Block 31 PSVM development in 2011-2012.

MARATHON FAST-TRACKED THE DEEPWATER DROSHKY PROJECT TO DELIVER PROFITABLE PRODUCTION GROWTH.

First oil from Droshky, a major Gulf of Mexico subsea oil development 160 miles off the Louisiana coast, is anticipated to come in on time and under budget in mid-2010. Marathon owns a 100 percent working interest in Droshky, which is expected to produce approximately 50 thousand net barrels of oil equivalent per day (mboepd) at its peak and develop net potential resources of 60 million barrels.

Executed properly, accelerated project development enhances both project and shareholder value. The Company was able to move Droshky forward at a rapid pace by making sound investment decisions quickly, applying technology skillfully at every stage of exploration and development, and rigorously implementing its project management system.

Located in Green Canyon 244 in 3,000 feet of water, Droshky is a technically complex undertaking. Marathon overcame numerous project challenges through seamless integration among the many functional teams involved and world-class front-end technical work, commercial skills and project planning.

The Company set a high standard of performance with Droshky, drilling and completing four wells to approximately 22,000 feet each in an average of 40 days. An external review rated this drilling performance number one among 72 deepwater Gulf of Mexico wells surveyed since 2007. Over the last decade, the same survey ranked Marathon's deepwater Gulf of Mexico drilling performance third among 20 participating operators.

State-of-the-art completion techniques at Droshky allow Marathon to capture reserves from 13 separate sand intervals in just four wells. Complex downhole equipment facilitates remote selection and production of zones during the life of the well. This approach will maximize capital efficiency and reduce or eliminate future well interventions.

In addition to significantly increasing production volumes in Marathon's Gulf of Mexico assets, Droshky is important because it supports the Company's technical view of the key Miocene play in the basin. Lessons learned on Droshky will be invaluable to Marathon's future exploration in the Gulf of Mexico.

MARATHON IS DEVELOPING EXPERTISE AND A TRACK RECORD IN UNCONVENTIONAL RESOURCE PLAYS.

Unconventional oil and natural gas resources with outstanding potential are a strategic growth area for Marathon. Since acquiring its first shale assets onshore the U.S. in 2006, the Company has developed specific competencies to address environmental, infrastructure, regulatory, geologic, drilling and completion challenges in shale plays. Its portfolio of U.S. unconventional holdings represents a total of 700 million barrels of oil equivalent (mmboe) net mean resource potential.

The North Dakota Bakken Shale oil play is Marathon's centerpiece unconventional resource and will be a top priority for its North America capital investment program in coming years. Within three years of entering the area, Marathon significantly increased and consolidated its initial position to approximately 336,000 net acres in high value areas.

The Company has set itself apart in the Bakken by cutting drilling time in half and implementing proactive environmental practices in sensitive areas located on federal and tribal lands. Net Bakken production has exceeded expectations and was 9.6 mboepd in 2009, up from 5.8 mboepd in 2008.

The Company is building a new core area in the Marcellus Shale in Pennsylvania and West Virginia. In the Oklahoma Woodford and Texas/Louisiana Haynesville areas, the resource plays have grown up under Marathon's existing conventional acreage positions. Marathon drilled its first shale gas wells in the Marcellus and Haynesville areas in 2009, and will expand drilling operations over the next several years.

Marathon is ready to transfer its expertise and repeat these shale oil and gas successes outside of the U.S. The Company was an early entrant in promising potential shale gas plays in Poland, where attractive commercial opportunities exist. In 2009 and January 2010, the Company was awarded a 100 percent working interest and operatorship in three concessions totaling 814,000 acres. The Lower Paleozoic shale gas objective is similar to many North American plays.

Improved reliability in Upstream operated facilities generated more than $200 million in revenues in 2009.

High operating reliability, which is central to Marathon's ability to grow production profitably, is paying off for Upstream. Results in 2009 showed a direct linkage between this key aspect of operational excellence and increased production and revenues. Dramatic reliability improvements and subsequent increased uptime in main operated assets boosted production more than 4.6 mmboe net compared to 2008.

Marathon's Equatorial Guinea LNG facility operated at 95 percent reliability in 2009, compared to 92 percent in the prior year. Higher reliability, coupled with innovative debottlenecking, increased production to 3.9 million metric tonnes of LNG in 2009. Marathon operated the Alba Field and Alba liquefied petroleum gas plant at 98 percent reliability, up from 93 percent in 2008, resulting in a nearly 5 percent increase in liquids and natural gas production year-over-year.

In the Alvheim/Vilje Development Area offshore Norway, overall reliability has exceeded plans since start-up in June 2008. Improved reliability, combined with optimization work, increased the throughput of the asset's floating production, storage and offloading vessel (FPSO) to 142 thousand barrels of oil per day (mbopd), up from the original design of 120 mbopd.

The Brae Complex is one of the most competitive mature assets in the U.K. North Sea. With investments in reliability improvements and other strategies, the Company has extended the expected life of Brae. Marathon achieved 93 percent reliability at Brae in 2009, compared to 85 percent in 2008.

Marathon also attained 98 percent reliability in its Gulf of Mexico and Alaska assets in 2009. In addition, Marathon is looking to improve reliability and increase production in its Canadian oil sands assets through cost-effective projects.

GME ENHANCES MARATHON'S FLEXIBILITY TO ADJUST FEEDSTOCKS, YIELDS AND PRODUCTS TO MARKET SHIFTS.

The Garyville Major Expansion (GME) demonstrates Marathon's ability to capture value from its integrated Downstream refining, marketing and transportation system. Garyville is the Company's most profitable refinery and one of the most efficient in the U.S., with crude processing capacity of 436 thousand barrels per day (mbpd), up from 256 mbpd. It is now the fourth-largest refinery in the U.S. The expansion is expected to provide substantial future cash flow to Marathon.

Completed on time, the refinery expansion is designed to use a wide variety of feedstocks and primarily produce high-value, high-margin gasoline and diesel. GME positions Marathon to benefit from the increased diesel demand that historically accompanies an economic recovery. GME also gives the Company the option to produce jet fuel to take advantage of market dynamics, to export diesel fuel and to shift asphalt production to other Marathon refineries.

While Garyville's operating efficiencies were already among the best in the industry, the expansion is expected to further reduce the refinery's fixed cash cost per barrel by an estimated 20 percent.

Garyville enjoys strategic logistical advantages for importing crude from anywhere in the world and distributing its refined products globally. Cost-effective regional pipeline, river and Gulf of Mexico transportation options give Marathon ready access to feedstocks and the flexibility to transport product to the highest value markets. And with Garyville's strategic location, the Company can tap increasing production from the Gulf of Mexico at a lower cost than Texas-based refiners.

To operate the state-of-the-art GME, Marathon hired and trained 200 new employees two years in advance. With the expansion complete, Garyville currently has 770 employees and 430 contract employees working at this refinery.

SSA IS WINNING MARKET SHARE AND TOP INDUSTRY RANKINGS WITH ITS COMPETITIVE STRATEGY.

Marathon's owned and operated retail marketing channel offers logistical, supply and economic benefits. With almost 2.5 million customers daily, Speedway SuperAmerica (SSA) is the third-largest company-owned and -operated convenience store chain in the U.S.

SSA gasoline and merchandise sales combined contributed more than $1.1 billion in gross margin in 2009. SSA same-store light product sales volumes increased by 1 percent in 2009, an estimated 2 percentage points higher than the change in demand in its market area. Total merchandise sales of $3.1 billion set a Company record and represented an annual same-store growth rate of 11.4 percent.

These results occurred despite SSA operating 66 fewer stores than five years ago. SSA strengthened its portfolio through the sale or closure of 155 non-core and underperforming stores and construction and acquisition of 89 new stores during this five-year period.

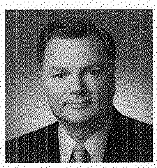
SSA is growing in a highly competitive industry as a result of its strategy and focus on expanding market share by staying true to its vision of being "the customer's first choice for value and convenience." SSA continues to execute efficiently, manage costs and deliver on its commitment to safety and environmental stewardship.

SSA has built a base of 3.2 million active customers who are members of its Speedy Rewards™ customer loyalty program, which celebrated its fifth anniversary in 2009. Based on their purchases at SSA locations, Speedy Rewards™ members earn points that can be redeemed for gasoline discounts, gift cards, food items and other merchandise. Active Speedy Rewards™ members make three times more trips to SSA stores than non-members, underscoring the value of strong customer loyalty.

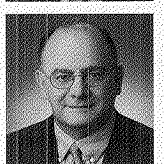
Speedway® was named the best gasoline brand in the U.S. in the 2009 EquiTrend® brand survey conducted nationally by Harris InterActive. SSA also has ranked number one in overall customer satisfaction in the convenience store industry for the past eight consecutive quarters in a national independent consumer perception survey conducted by Corporate Research International®.

Marathon Oil Corporation Leadership

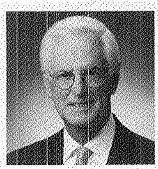
Board of Directors



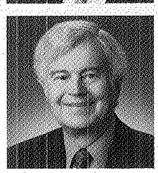
Gregory H. Boyce,[1,2,4] 55, Chairman and Chief Executive Officer, Peabody Energy Corporation. Mr. Boyce serves on the Boards of Directors of the Business Round Table, the American Coalition for Clean Coal Electricity (ACCCE), the National Mining Association and World Coal Institute. He is also a member of the Board of Trustees of Washington University of St. Louis and the St. Louis Children's Hospital.



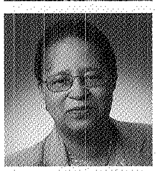
Clarence P. Cazalot Jr., 59, President and Chief Executive Officer, Marathon Oil Corporation. Mr. Cazalot serves on the Boards of Directors of Baker Hughes Incorporated, the U.S.-Saudi Arabian Business Council, the American Petroleum Institute and the Greater Houston Partnership. He is a member of The Business Council and serves on the Advisory Board of the World Affairs Council of Houston.



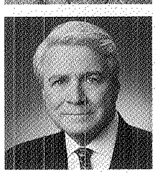
David A. Daberko,[1,2**,3] 64, Retired Chairman of the Board, National City Corporation. Mr. Daberko serves on the Board of Directors of RPM International, Inc. He is a Trustee of Case Western Reserve University, University Hospitals Health System and Hawken School.



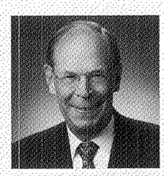
William L. Davis,[1,3,4] 66, Retired Chairman, President and Chief Executive Officer, R.R. Donnelley & Sons Company. Mr. Davis serves on the Boards of Directors of Air Products and Chemicals, Inc. and Northshore University Health System, previously serving as Chairman of the Board, and is a former Director of Mallinckrodt.



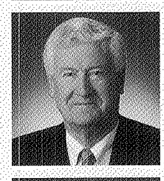
Dr. Shirley Ann Jackson,[1**,2,4] 63, President, Rensselaer Polytechnic Institute. Dr. Jackson serves on the Boards of Directors of FedEx Corporation, International Business Machines Corporation, Medtronic, Inc. and Public Service Enterprise Group Incorporated. She is also Chairman of NYSE Regulation, Inc. Dr. Jackson is a member of the Board of Regents of the Smithsonian Institution, is a life member of the MIT Corporation and serves on the Board of the Council on Foreign Relations.



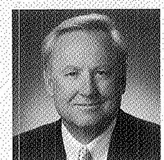
Philip Lader,[3,4**] 63, Non-executive Chairman, WPP plc. Ambassador Lader is senior advisor to Morgan Stanley and a partner in the law firm of Nelson, Mullins, Riley & Scarborough. He also serves on the Boards of Directors of AES Corporation, United Company RUSAL and Lloyd's (of London), and is a member of the Boards of Trustees of the Smithsonian Museum of American History, RAND Corporation and The Atlantic Council.



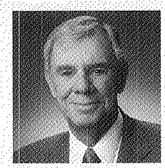
Charles R. Lee,[1,2,4] 69, Retired Chairman of the Board, Verizon Communications Inc. Mr. Lee serves on the Boards of Directors of United States Steel Corporation, The Proctor & Gamble Company, United Technologies Corporation and DIRECTV. Mr. Lee is a member of the Board of Overseers of Weill Cornell Medical College and is a member of The Business Council. Mr. Lee is also a Trustee Emeritus and Presidential Councilor of Cornell University.



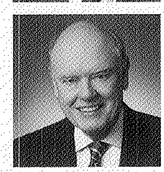
Michael E. J. Phelps,[1,3,4] 62, Chairman and Founder, Dornoch Capital, Inc. He serves as Chairman of Kodiak Exploration Ltd. and is on the Boards of Directors of Canadian Pacific Railway Company and Spectra Energy Corporation. He also serves as Chairman of the Globe Foundation, is Vice Chairman of VGH and UBC Hospital Foundation and is a member of Deutsche Bank Americas Advisory Board.



Dennis H. Reilley,[2,3**,4] 56, Former Non-executive Chairman, Covidien Ltd. Mr. Reilley serves on the Boards of Directors of H. J. Heinz Co., Dow Chemical Company, Covidien Ltd. and the Conservation Fund. He is the former Chairman of the American Chemistry Council.



Seth E. Schofield,[1,2,3] 70, Retired Chairman and Chief Executive Officer, USAir Group. Mr. Schofield serves as a Presiding Director of United States Steel Corporation and Lead Director of Calgon Carbon Corp.



John W. Snow,[2,3,4] 70, Chairman, Cerberus Capital Management L.P., and former Secretary of the Treasury. Mr. Snow is a Director of Verizon Communications, Inc. Before joining the Bush Administration, he served on various corporate and nonprofit boards, including the American Enterprise Institute and Johns Hopkins University. He previously served as a member of USX Corporation's Board of Directors from March 1995 through December 2001.

Thomas J. Usher, 67, Non-executive Chairman of the Board, Marathon Oil Corporation. Mr. Usher serves on the Boards of Directors of H. J. Heinz Co., The PNC Financial Services Group, Inc. and PPG Industries, Inc. He is a member of the Board of Trustees of the University of Pittsburgh and a Board of Directors member of the Extra Mile Education Foundation. Mr. Usher is a member of The Business Council.

1 Audit and Finance Committee
2 Compensation Committee
3 Corporate Governance and Nominating Committee
4 Public Policy Committee
**Chair of Committee

Officers

Corporate Officers

Clarence P. Cazalot Jr., 59, President and Chief Executive Officer
Janet F. Clark, 55, Executive Vice President and Chief Financial Officer
Gary R. Heminger, 56, Executive Vice President—Downstream
David E. Roberts Jr., 49, Executive Vice President—Upstream
Jerry Howard, 61, Senior Vice President—Corporate Affairs
Eileen M. Campbell, 52, Vice President—Human Resources
Sylvia J. Kerrigan, 44, Vice President, General Counsel and Secretary
Stephen J. Landry, 48, Vice President—Tax
Paul C. Reinbolt, 54, Vice President—Finance and Treasurer
R. Douglas Rogers, 47, Vice President—Health, Environment, Safety and Security
Thomas K. Sneed, 51, Chief Information Officer
Michael K. Stewart, 52, Vice President—Accounting and Controller
Daniel J. Sullenbarger, 58, Vice President—Corporate Compliance and Ethics
Howard J. Thill, 50, Vice President—Investor Relations and Public Affairs

Company Officers

Anthony R. Kenney, 56, President—Speedway SuperAmerica LLC
Steve D.L. Reynish, 51, President—Marathon Oil Canada Corporation
Annell R. Bay, 54, Senior Vice President—Exploration
Clifford C. Cook, 64, Senior Vice President—Supply, Distribution and Planning
Thomas M. Kelley, 50, Senior Vice President—Marketing
Garry L. Peiffer, 58, Senior Vice President—Finance and Commercial Services
Mary Ellen Peters, 52, Senior Vice President—Transportation and Logistics
Jerry C. Welch, 59, Senior Vice President—Refining
Pamela K.M. Beall, 53, Vice President—Global Procurement
Linda A. Capuano, 58, Vice President—Emerging Technology
Robert E. Estill, 50, Vice President—Strategic Planning and Portfolio Management
Patrick J. Kuntz, 60, Vice President—Natural Gas and Crude Oil Sales
Randy K. Lohoff, 57, Vice President—Corporate Responsibility
Rodney P. Nichols, 57, Vice President—Human Resources and Administrative Services
Michael A. Peak, 56, Vice President—Risk Management and Trading
Tim N. Tipton, 54, Vice President—Upstream Technology
J. Michael Wilder, 58, Associate General Counsel

All ages as of February 1, 2010

Cautionary Note and Statement for the Purposes of the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995

The United States Securities and Exchange Commission (SEC) permits oil and gas companies, in their filings with the SEC, to disclose proved, probable or possible reserves. In this summary annual report wrap, we use certain terms to refer to reserves other than proved, probable or possible reserves, which the SEC's guidelines strictly prohibit us from including in filings with the SEC. These terms include resource base, unrisked resource potential, net potential resources, net mean resource potential, total mean resource, total resource and other similar terms, which are not yet classified as proved, probable or possible reserves. U.S. investors are urged to consider closely the disclosures in our Form 10-K. You can obtain this form from the SEC by calling 1-800-SEC-0330. This summary annual report wrap also contains forward-looking statements about Marathon's four business segments: (1) exploration and production; (2) oil sands mining; (3) integrated gas; and (4) refining, marketing and transportation. Such statements include, but are not limited to, the Droshky development in the Gulf of Mexico; other existing and potential developments, including the timing and levels of production; future exploration and drilling activity; potential development in Poland; additional reserves; potential developments in Angola; new leaseholds in Indonesia; the AOSP Expansion; and carbon capture and sequestration. Where, in any forward-looking statement, the Company expresses an expectation or belief as to future results, such expectation or belief is expressed in good faith and believed to have a reasonable basis. However, there can be no assurance that the statement of expectation or belief will result or be achieved. These statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied by such statements. In accordance with the "Safe Harbor" provisions of the Private Securities Litigation Reform Act of 1995, Marathon has included in its attached Form 10-K for the year ended December 31, 2009, cautionary language identifying important factors, though not necessarily all such factors, that could cause future outcomes to differ materially from those set forth in the forward-looking statements.

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

FORM 10-K

**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2009**

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 if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

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 and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ 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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

Yes ☐ No ☑

The aggregate market value of Common Stock held by non-affiliates as of June 30, 2009: $21,272 million. This amount is based on the closing price of the registrant's Common Stock on the New York Stock Exchange on that date. Shares of Common Stock held by executive officers and directors of the registrant are not included in the computation. However, the registrant has made no determination that such individuals are "affiliates" within the meaning of Rule 405 of the Securities Act of 1933.

There were 707,926,768 shares of Marathon Oil Corporation Common Stock outstanding as of January 29, 2010.

Documents Incorporated By Reference:

Portions of the registrant's proxy statement relating to its 2010 annual meeting of stockholders, to be filed with the Securities and Exchange Commission pursuant to Regulation 14A under the Securities Exchange Act of 1934, are incorporated by reference to the extent set forth in Part III, Items 10-14 of this report.

MARATHON OIL CORPORATION

Unless the context otherwise indicates, references to "Marathon," "we," "our," or "us" in this Annual Report on Form 10-K 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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Disclosures Regarding Forward-Looking Statements

This Annual Report on Form 10-K, particularly Item 1. Business, Item 1A. Risk Factors, Item 3. Legal Proceedings, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 7A. Quantitative and Qualitative Disclosures about Market Risk, includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These statements typically contain words such as "anticipate," "believe," "estimate," "expect," "forecast," "plan," "predict," "target," "project," "could," "may," "should," "would" or 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, that could cause future outcomes to differ materially from those set forth in the forward-looking statements.

Forward-looking statements in this Report may include, but are not limited to, levels of revenues, gross margins, income from operations, net income or earnings per share; levels of capital, exploration, environmental or maintenance expenditures; the success or timing of completion of ongoing or anticipated capital, exploration or maintenance projects; volumes of production, sales, throughput or shipments of liquid hydrocarbons, natural gas, synthetic crude oil and refined products; levels of worldwide prices of liquid hydrocarbons, natural gas and refined products; levels of reserves of liquid hydrocarbons, natural gas and synthetic crude oil; the acquisition or divestiture of assets; the effect of restructuring or reorganization of business components; the potential effect of judicial proceedings on our business and financial condition; levels of common share repurchases; and the anticipated effects of actions of third parties such as competitors, or federal, foreign, state or local regulatory authorities.

PART I

Item 1. Business

General

Marathon Oil Corporation was originally organized in 2001 as USX HoldCo, Inc., a wholly-owned subsidiary of the former USX Corporation. As a result of a reorganization completed in July 2001, USX HoldCo, Inc. (1) became the parent entity of the consolidated enterprise (the former USX Corporation was merged into a subsidiary of USX HoldCo, Inc.) and (2) changed its name to USX Corporation. In connection with the transaction described in the next paragraph (the "USX Separation"), USX Corporation changed its name to Marathon Oil Corporation.

Before December 31, 2001, Marathon had two outstanding classes of common stock: USX-Marathon Group common stock, which was intended to reflect the performance of our energy business, and USX-U.S. Steel Group common stock ("Steel Stock"), which was intended to reflect the performance of our steel business. On December 31, 2001, we disposed of our steel business through a tax-free distribution of the common stock of our wholly-owned subsidiary United States Steel Corporation ("United States Steel") to holders of Steel Stock in exchange for all outstanding shares of Steel Stock on a one-for-one basis.

In connection with the USX Separation, our certificate of incorporation was amended on December 31, 2001, and Marathon has had only one class of common stock authorized since that date.

On June 30, 2005, we acquired the 38 percent ownership interest in Marathon Ashland Petroleum LLC ("MAP") previously held by Ashland Inc. ("Ashland"). In addition, we acquired a portion of Ashland's Valvoline Instant Oil Change business, its maleic anhydride business, its interest in LOOP LLC which owns and operates the only U.S. deepwater oil port, and its interest in LOCAP LLC which owns a crude oil pipeline. As a result of the transactions, MAP is wholly owned by Marathon and its name was changed to Marathon Petroleum Company LLC ("MPC") effective September 1, 2005.

On October 18, 2007, we acquired all the outstanding shares of Western Oil Sands Inc. ("Western"). Western's primary asset was a 20 percent interest in the outside-operated Athabasca Oil Sands Project ("AOSP"), an oil sands mining joint venture located in the province of Alberta, Canada. The acquisition was accounted for under the purchase method of accounting and, as such, our results of operations include Western's results from October 18, 2007. Western's oil sands mining and bitumen upgrading operations are reported as a separate Oil Sands Mining segment, while its ownership interests in leases where in-situ recovery techniques are expected to be utilized are included in the Exploration and Production segment.

Segment and Geographic Information

Our operations consist of four reportable operating segments: 1) Exploration and Production ("E&P") – explores for, produces and markets liquid hydrocarbons and natural gas on a worldwide basis; 2) Oil Sands Mining ("OSM") – mines, extracts and transports bitumen from oil sands deposits in Alberta, Canada, and upgrades the bitumen to produce and market synthetic crude oil and vacuum gas oil; 3) Integrated Gas ("IG") – markets and transports products manufactured from natural gas, such as liquefied natural gas ("LNG") and methanol, on a worldwide basis; and 4) Refining, Marketing and Transportation ("RM&T") – refines, transports and markets crude oil and petroleum products, primarily in the Midwest, upper Great Plains, Gulf Coast and southeastern regions of the United States. For operating segment and geographic financial information, see Note 9 to the consolidated financial statements.

The E&P, OSM and IG segments comprise our upstream operations. The RM&T segment comprises our downstream operations.

Exploration and Production

In the discussion that follows regarding our exploration and production operations, references to "net" wells, sales or investment indicate our ownership interest or share, as the context requires.

At the end of 2009, we were conducting oil and gas exploration, development and production activities in eight countries: the United States, Angola, Canada, Equatorial Guinea, Indonesia, Libya, Norway and the United Kingdom. During 2009, we exited Gabon and Ireland. We plan to begin exploration activities in Poland during 2010.

Our 2009 worldwide net liquid hydrocarbon sales averaged 243 thousand barrels per day ("mbpd"). Our 2009 worldwide net natural gas sales, including natural gas acquired for injection and subsequent resale, averaged 941 million cubic feet per day ("mmcfd"). In total, our 2009 worldwide net sales averaged 400 thousand barrels of oil equivalent per day ("mboepd"). For purposes of determining barrels of oil equivalent ("boe"), natural gas volumes are converted to approximate liquid hydrocarbon barrels by dividing the natural gas volumes expressed in thousands of cubic feet ("mcf") by six. The liquid hydrocarbon volume is added to the barrel equivalent of natural gas volume to obtain boe. These volumes exclude 7 mboepd related to discontinued operations.

In the United States during 2009, we drilled 76 gross (50 net) exploratory wells of which 72 gross (48 net) wells encountered commercial quantities of hydrocarbons. Of these 72 wells, 6 were temporarily suspended or in the process of being completed at year end. Internationally, we drilled 9 gross (1 net) exploratory wells of which 6 gross (1 net) wells encountered commercial quantities of hydrocarbons. All 6 wells were temporarily suspended or were in the process of being completed at December 31, 2009.

North America

United States – Our U.S. operations accounted for 26 percent of our 2009 worldwide net liquid hydrocarbon sales volumes and 40 percent of our worldwide net natural gas sales volumes.

Offshore – The Gulf of Mexico continues to be a core area. During 2009, our net sales in the Gulf of Mexico averaged 24 mbpd of liquid hydrocarbons and 20 mmcfd of natural gas. At year end 2009, we held interests in seven producing fields and four platforms in the Gulf of Mexico, of which we operate one platform.

We operate the Ewing Bank 873 platform which is located 130 miles south of New Orleans, Louisiana. The platform started operations in 1994 and serves as a production hub for the Lobster, Oyster and Arnold fields. The facility also processes third-party production via subsea tie-backs.

We own a 50 percent interest in the outside-operated Petronius field on Viosca Knoll Blocks 786 and 830. An additional development well was successfully completed in 2009. The Petronius platform is capable of providing processing and transportation services to nearby third-party fields.

The Neptune development commenced production of liquid hydrocarbons and natural gas in July 2008. We hold a 30 percent working interest in this outside-operated development located on Atwater Valley 575, 120 miles off the coast of Louisiana. The completed Phase I development included six subsea wells tied back to a stand-alone platform. Phase II development activities have begun and the first well in this program was successfully drilled and completed in late 2009.

Development of the Droshky discovery, located on Green Canyon Block 244, continued in 2009. Droshky Phase I is a four well liquid hydrocarbon development with first production targeted for mid-year 2010. Ongoing development activities include running intelligent well completions, installation of the subsea facilities and topside modifications to the third-party Bullwinkle host platform. Expected net peak production is approximately 50 mboepd. We hold a 100 percent operated working interest in Droshky.

Development of the Ozona prospect, located on Garden Banks Block 515, has also continued. We have secured a rig to complete the previously drilled appraisal well and tie back to the nearby third-party Auger platform. First production is expected in 2011. We hold a 68 percent working interest in Ozona.

In 2008, we drilled a successful liquid hydrocarbon appraisal well on the Stones prospect located on Walker Ridge Block 508. We hold a 25 percent interest in the outside-operated Stones prospect. In the third quarter of 2008, we announced deepwater liquid hydrocarbon discovery on the Gunflint prospect located on Mississippi Canyon Block 948. We own a 13 percent interest in this outside-operated prospect. In the first quarter of 2009, we participated in a deepwater liquid hydrocarbon discovery on the Shenandoah prospect located on Walker Ridge Block 52. We own a 20 percent interest in the outside-operated prospect. In December 2009, we began drilling the Flying Dutchman well, on Green Canyon Block 511, where we have 63 percent ownership and are the operator of this liquid hydrocarbon prospect.

In addition to the prospects listed above, we held interests in 103 blocks in the Gulf of Mexico at the end of 2009, including 97 in the deepwater area. Our plans call for exploration drilling on some of these leases in 2010 and 2011.

Onshore – We produce natural gas in the Cook Inlet and adjacent Kenai Peninsula of Alaska. We have operated and outside-operated interests in 10 fields and hold a 51 to 100 percent working interest in each. In 2009, our net natural gas sales from Alaska averaged 87 mmcfd. Typically, our natural gas sales from Alaska are seasonal in nature, trending down during the second and third quarters of each year and increasing during the fourth and first quarters. To manage supplies to meet contractual demand we produce and store natural gas in a partially depleted reservoir in the Kenai natural gas field. In 2009, we drilled six wells in Alaska and plan to drill four to six wells per year during 2010 through 2012.

We hold leases with natural gas production in the Piceance Basin of Colorado, located in Garfield County in the Greater Grand Valley field complex. Our plans include drilling approximately 65 wells over the next five years. We currently have one operated drilling rig running and averaged net sales of 15 mmcfd in 2009.

We hold 336,000 acres over the Bakken Shale oil play in the Williston Basin of North Dakota with a working interest of approximately 84 percent. Approximately 225 locations will be drilled over the next four to five years. We are evaluating other potential horizons above and below the Middle Bakken. We currently have four operated drilling rigs running in our Bakken program. We exited 2009 with average net sales of 11 mboepd in December.

In 2008, we successfully completed our first horizontal well in the Woodford Shale natural gas play in the Anadarko Basin of Oklahoma. We are currently participating in additional horizontal wells in the area where we hold 52,000 net acres. In 2009, we drilled 13 wells, five of which were operated. We plan to drill 10 to 15 wells in 2010.

We also have domestic natural gas operations in Oklahoma, east Texas and north Louisiana, with combined net sales of 121 mmcfd in 2009, and liquid hydrocarbon operations in the Permian Basin of west Texas, with net sales of 8 mbpd in 2009. In June 2009, we completed the sales of our operated and a portion of our outside-operated Permian Basin producing assets in New Mexico and west Texas. We still retain interests in 12 Permian Basin fields.

We hold acreage in two additional emerging shale resource plays in the U.S. In the Appalachian Basin we hold 70,000 net acres in the Marcellus Shale natural gas play in Pennsylvania and West Virginia. We drilled five wells in 2009 and plan to drill another 8 to 12 wells in 2010. In Louisiana and east Texas, we hold 25,000 net acres in the Haynesville Shale natural gas play, where we drilled one well in 2009. We plan to drill three to four wells in 2010.

Net liquid hydrocarbon and natural gas sales from our Wyoming fields averaged 18 mbpd and 113 mmcfd in 2009. We plan to drill 24 wells in 2010.

Canada – We hold interests in both operated and outside-operated exploration stage in-situ oil sand leases as a result of the acquisition of Western in 2007. The three potential in-situ developments are Namur, in which we hold a 60 percent operated interest, Birchwood, in which we hold a 100 percent operated interest, and Ells River, in which we hold a 20 percent outside-operated interest. Initial test drilling on the Birchwood prospect positively confirmed bitumen presence with additional test drilling required to confirm reservoir quality.

Africa

Equatorial Guinea – We own a 63 percent operated working interest in the Alba field which is offshore Equatorial Guinea. During 2009, net liquid hydrocarbon sales averaged 42 mbpd, or 17 percent of our worldwide net liquid hydrocarbon sales volumes, and net natural gas sales averaged 426 mmcfd, or 45 percent of our worldwide net natural gas sales. Net liquid hydrocarbon sales volumes in 2009 included 30 mbpd of primary condensate.

We also own a 52 percent interest in Alba Plant LLC, an equity method investee that operates an onshore liquefied petroleum gas ("LPG") processing plant. Alba field natural gas is processed by the LPG plant under a long-term contract at a fixed price for the British thermal units used in the operations of the LPG plant and for the hydrocarbons extracted from the natural gas stream in the form of secondary condensate and LPG. During 2009, a gross 943 mmcfd of natural gas was supplied to the LPG production facility and the resulting net liquid hydrocarbon sales volumes in 2009 included 4 mbpd of secondary condensate and 12 mbpd of LPG produced by Alba Plant LLC.

As part of our Integrated Gas segment, we own 45 percent of Atlantic Methanol Production Company LLC ("AMPCO") and 60 percent of Equatorial Guinea LNG Holdings Limited ("EGHoldings"), both of which are accounted for as equity method investments. AMPCO operates a methanol plant and EGHoldings operates a liquefied natural gas ("LNG") production facility, both located on Bioko Island. Dry natural gas from the Alba field, which remains after the condensate and LPG are removed, is supplied to both of these facilities under long-term contracts at fixed prices. Because of the location of and limited local demand for natural gas in Equatorial Guinea, we consider the prices under the contracts with Alba Plant LLC, AMPCO and EGHoldings to be comparable to the price that could be realized from transactions with unrelated parties in this market under the same or similar circumstances. Our share of the income ultimately generated by the subsequent export of secondary condensate and LPG produced by Alba Plant LLC is reflected in our E&P segment. Our share of the income ultimately generated by the subsequent export of methanol produced by AMPCO and LNG produced by EGHoldings is reflected in our Integrated Gas segment as discussed below. During 2009, a gross 115 mmcfd of dry natural gas was supplied to the methanol plant and a gross 647 mmcfd of dry gas was supplied to the LNG production facility. Any remaining dry gas is returned offshore and reinjected back into the Alba field for later production.

We hold a 63 percent operated interest in the Deep Luba and Gardenia discoveries on the Alba Block and we are the operator with a 90 percent interest in the Corona well on Block D. These wells are part of our long-term LNG strategy. We expect these discoveries to be developed when the natural gas supply from the nearby Alba field starts to decline.

Angola – Offshore Angola, we hold 10 percent interests in Block 31 and Block 32, both of which are outside-operated. The discoveries on Blocks 31 and 32 represent four potential development hubs. The Plutao, Saturno, Venus and Marte discoveries and one successful appraisal well form a planned development area in the northeastern portion of Block 31. In 2008, we received approval to proceed with this first deepwater development project, called the PSVM development. The PSVM development will utilize a floating, production, storage and offloading ("FPSO") vessel. A total of 48 production and injection wells are planned with the drilling of the first three to four development wells planned in 2010. First production is anticipated in late 2011 to early 2012. Other discoveries on Block 31 comprise potential development areas in the southeast and middle portions of the block. Eight of the Block 32 discoveries form a potential development in the eastern area of that block. We expect first production on Block 32 in 2015 or 2016.

Libya – We hold a 16 percent interest in the outside-operated Waha concessions, which encompass almost 13 million acres located in the Sirte Basin. Our exploration program in 2009 included the drilling of four wells. One well is waiting on completion, one was dry and abandoned, and two are currently drilling. We also drilled 5 development wells in Libya during the year. Net liquid hydrocarbon sales in Libya averaged 46 mbpd in 2009. The 2009 net liquid hydrocarbon sales in Libya represented 19 percent of our worldwide net liquid hydrocarbon sales volumes. Net natural gas sales in Libya averaged 4 mmcfd in 2009.

Our Faregh Phase II Gas Plant project is expected to deliver a gross 180 mmcfd of natural gas and 15 mbpd of liquid hydrocarbons into the Libyan domestic market. Commissioning will begin in 2010, with startup planned for first quarter of 2011.

Europe

Norway – Norway is a growing core area, which complements our long-standing operations in the U.K. sector of the North Sea discussed below. We were approved for our first operatorship on the offshore Norwegian continental shelf in 2002, where today we operate eight licenses and hold interests in over 600,000 gross acres.

The operated Alvheim complex located on the Norwegian continental shelf commenced production in June 2008. The complex consists of an FPSO with subsea infrastructure. Improved reliability, combined with optimization work, increased the throughput of the FPSO to 142 mbpd, up from the original design of 120 mbpd. Produced oil is transported by shuttle tanker and produced natural gas is transported to the existing U.K. Scottish Area Gas Evacuation ("SAGE") system using a 14-inch diameter, 24-mile cross border pipeline. First production to the complex was from the Alvheim development which is comprised of the Kameleon, East Kameleon and Kneler fields, in which we have a 65 percent working interest, and the Boa field, in which we have a 58 percent working interest. At the end of 2009, the Alvheim development included ten producing wells and two water disposal wells. A Phase 2 drilling program targeting three additional production wells, and a Phase 2b drilling program with two additional production wells, is planned in 2010 through 2012. Net sales for 2009 averaged 56 mbpd of liquid hydrocarbons and 30 mmcfd of natural gas.

The nearby outside-operated Vilje field, in which we own a 47 percent working interest, began producing through the Alvheim complex in August 2008. During 2009, net liquid hydrocarbon sales from Vilje averaged 12 mbpd.

In June 2009, we completed the drilling program for the Volund field as a subsea tieback to the Alvheim complex. The Volund development, in which we own a 65 percent operated interest, is located approximately five miles south of the Alvheim area and consists of one production well and one water disposal well. First production from Volund was announced in September 2009. The Volund owners have contracted for 25 gross mbpd (16 mbpd net) firm capacity on the Alvheim FPSO beginning in July 2010. Until that date, Volund will act as a swing producer, filling any available capacity and allowing the FPSO to be fully utilized.

Also offshore Norway, we and our partners announced the Marihone and Viper discoveries, both located within tie-back distance of the Alvheim FPSO. The Marihone oil discovery is located in license PL340 about 12 miles south of the Volund and Alvheim fields. We hold a 65 percent operated working interest in Marihone. The Viper oil discovery is located immediately next to Volund field in PL203, about 12 miles south of the Alvheim FPSO. We are the operator and hold a 65 percent interest in Viper. Conceptual development studies for both discoveries have begun.

In addition, we hold a 28 percent interest in the outside-operated Gudrun field, located 120 miles off the coast of Norway. In January 2009, the operator announced a development concept that includes a fixed processing platform with seven production wells that would be tied to existing facilities on the Sleipner field, and one water disposal well.

United Kingdom – Our largest asset in the U.K. sector of the North Sea is the Brae area complex where we are the operator and have a 42 percent working interest in the South, Central, North and West Brae fields and a 38 percent working interest in the East Brae field. The Brae A platform and facilities host the underlying South Brae field and the adjacent Central and West Brae fields. A two well development program is scheduled in 2010 for West Brae. The North Brae field, which is produced via the Brae B platform, and the East Brae field, which is produced via the East Brae platform, are natural gas condensate fields. The East Brae platform hosts the nearby Braemar field in which we have a 28 percent working interest. Net liquid hydrocarbon sales from the Brae area averaged 11 mbpd in 2009. Net Brae natural gas sales averaged 101 mmcfd, or 11 percent of our worldwide net natural gas sales volumes, in 2009.

The strategic location of the Brae platforms along with pipeline and onshore infrastructure has generated third-party processing and transportation business since 1986. Currently, the operators of 28 third-party fields have contracted to use the Brae system. In addition to generating processing and pipeline tariff revenue, this third-party business also has a favorable impact on Brae area operations by optimizing infrastructure usage and extending the economic life of the complex.

The Brae group owns a 50 percent interest in the outside-operated Scottish Area Gas Evacuation ("SAGE") system. The SAGE pipeline transports natural gas from the Brae area, and the third-party Beryl area, and has a total wet natural gas capacity of 1.1 billion cubic feet ("bcf") per day. The SAGE terminal at St. Fergus in northeast Scotland processes natural gas from the SAGE pipeline as well as approximately 1 bcf per day of third-party natural gas.

In the U.K. Atlantic Margin west of the Shetland Islands, we own an average 30 percent working interest in the outside-operated Foinaven area complex, consisting of a 28 percent working interest in the main Foinaven field, 47 percent working interest in East Foinaven and 20 percent working interest in the T35 and T25 fields. Net sales from the Foinaven fields averaged 13 mbpd of liquid hydrocarbons and 7 mmcfd of natural gas in 2009. We are upgrading the FPSO which will extend the life of this project through 2021.

We have a 45 percent interest in five exploratory U.K. onshore coal seam gas licenses. Drilling has been completed in five exploration wells in three of the licenses. We also hold a 55 percent operated working interest in 11 blocks awarded in a 2008 bid round. Our interest covers 520,000 gross acres.

Poland – We have recently added a new opportunity to our portfolio, Poland shale gas. In November we were awarded the 296,000 acre Kwidzyn Block, followed by the 249,000 acre Orzechow Block in December. The five and a half year exploration phase for each block includes 2D seismic and at least one well. We were awarded the 269,000 acre Brodnica Block in January 2010, and we continue to look for additional opportunities in Poland. We hold a 100 percent interest and operatorship in all three blocks.

Other International

Indonesia – We are the operator and hold a 70 percent interest in the Pasangkayu Block offshore Indonesia. The block is located mostly in deep water, predominantly offshore of the island of Sulawesi in the Makassar Strait, directly east of the Kutei Basin production region. The production sharing contract with the Indonesian government was signed in 2006 and we completed 3D seismic acquisition in May 2008. A mandatory 25 percent relinquishment was submitted to the Indonesian government in September 2009 and upon approval, the block size will be reduced from 1.2 million gross acres to 872,400 gross acres. We expect to drill two wells in 2010.

In October 2008, we were granted a 49 percent interest and operatorship in the Bone Bay Block offshore Sulawesi. An increase in ownership to 55 percent is pending Indonesian government approval. The Bone Bay Block covers an area of 1.23 million acres and is 200 miles southeast of our Pasangkayu Block. Current exploration plans for Bone Bay call for the acquisition of seismic data starting in 2010, followed by drilling of one exploration well in 2011. In the second quarter of 2009, we were awarded a 49 percent interest and operatorship in the Kumawa Block, our third Indonesia offshore exploration block, located offshore West Papua. An increase in ownership to 55 percent is pending Indonesian government approval. The Kumawa Block encompasses 1.24 million acres. A 2D seismic survey is planned in the first quarter of 2010 and we expect to drill one exploration well in 2011-2012.

We are the operator of a drilling rig consortium, with five other operators, that has secured a deepwater exploration drilling rig to drill exploratory wells in Indonesia over a two-year period commencing in the second quarter of 2010. The participants have the right to extend this rig contract for up to one additional year.

We continue to participate in joint study agreements in Indonesia, which provide a right of first refusal in future bid rounds. We completed two joint study agreements in 2008 and have one in progress.

Divestitures

Angola – In February 2010, we closed the sale of an undivided 20 percent interest in the outside-operated production sharing contract and joint operating agreement on Block 32 offshore Angola for $1.3 billion, excluding any purchase price adjustments, with an effective date of January 1, 2009. We retained a 10 percent interest in Block 32.

Gabon – In December 2009, we closed the sale of our operated properties in Gabon. Net production from these operations averaged 6 mbpd in 2009. The results of our Gabonese operations have been reported as discontinued operations.

United States – In June 2009, we completed the sale of our operated and a portion of our outside-operated Permian Basin producing assets in New Mexico and west Texas for net proceeds after closing adjustments of $293 million. A $196 million pretax gain on the sale was recorded. Net production from these sold properties averaged 8,150 boepd in the first quarter of 2009.

Ireland – In April 2009, we closed the sale of our operated properties offshore Ireland, which consisted of our 100 percent working interest in the Kinsale Head, Ballycotton and Southwest Kinsale natural gas fields and our 87 percent working interest in the Seven Heads natural gas field. Net production from these operations averaged 5 mboepd in the first quarter of 2009.

In July 2009 we closed the sale of our subsidiary holding our 19 percent interest in the outside-operated Corrib natural gas development offshore Ireland. As a result of these dispositions, our Irish exploration and production businesses have been reported as discontinued operations.

The above discussion of the E&P segment includes forward-looking statements with respect to anticipated future exploratory and development drilling, the timing of production from the Droshky and Ozona developments in the Gulf of Mexico, the Faregh Phase II Gas Plant, the PSVM development on Block 31 offshore Angola and Block 32 and other possible developments. Some factors which 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, drilling rig availability, unforeseen hazards such as weather conditions, natural disasters, 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 offshore developments could further be affected by presently known data concerning size and character of reservoirs, economic recoverability, future drilling success and production experience. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Productive and Drilling Wells

For our E&P segment, the following tables set forth productive wells and service wells as of December 31, 2009, 2008 and 2007 and drilling wells as of December 31, 2009.

Gross and Net Wells

	Productive Wells (a)							
	Oil		Natural Gas		Service Wells		Drilling Wells	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
2009								
United States	4,806	1,788	5,158	3,569	2,447	734	31	18
Equatorial Guinea	-	-	13	9	5	3	-	-
Other Africa	976	160	-	-	91	15	6	1
Total Africa	976	160	13	9	96	18	6	1
Total Europe	67	27	44	18	27	10	-	-
WORLDWIDE	5,849	1,975	5,215	3,596	2,570	762	37	19
2008								
United States	5,856	2,140	5,411	3,846	2,703	822		
Equatorial Guinea	-	-	13	9	5	3		
Other Africa	968	162	-	-	92	15		
Total Africa	968	162	13	9	97	18		
Total Europe	64	26	67	40	26	10		
WORLDWIDE	6,888	2,328	5,491	3,895	2,826	850		
2007								
United States	5,864	2,111	5,184	3,734	2,737	838		
Equatorial Guinea	-	-	13	9	5	3		
Other Africa	964	161	-	-	94	15		
Total Africa	964	161	13	9	99	18		
Total Europe	54	20	76	41	29	11		
WORLDWIDE	6,882	2,292	5,273	3,784	2,865	867		

(a) Of the gross productive wells, wells with multiple completions operated by Marathon totaled 170, 276 and 303 as of December 31, 2009, 2008 and 2007. Information on wells with multiple completions operated by others is unavailable to us.

Drilling Activity

The following table sets forth, by geographic area, the number of net productive and dry development and exploratory wells completed in each of the last three years.

Net Productive and Dry Wells Completed

	Development				Exploratory				Total
	Oil	Natural Gas	Dry	Total	Oil	Natural Gas	Dry	Total	
2009									
United States	11	54	2	67	37	9	2	48	115
Total Africa	5	1	-	6	1	-	-	1	7
Total Europe	1	-	-	1	1	-	-	1	2
WORLDWIDE	17	55	2	74	39	9	2	50	124
2008									
United States	38	161	-	199	33	8	6	47	246
Total Africa	6	-	-	6	1	-	-	1	7
Total Europe	2	1	-	3	-	2	1	3	6
WORLDWIDE	46	162	-	208	34	10	7	51	259
2007									
United States	9	172	-	181	9	13	12	34	215
Total Africa	4	-	-	4	3	-	1	4	8
Total Europe	3	-	-	3	-	1	1	2	5
WORLDWIDE	16	172	-	188	12	14	14	40	228

Acreage

The following table sets forth, by geographic area, the developed and undeveloped exploration and production acreage held in our E&P segment as of December 31, 2009.

Gross and Net Acreage

	Developed		Undeveloped		Developed and Undeveloped	
(Thousands of acres)	Gross	Net	Gross	Net	Gross	Net
United States	1,507	1,142	1,359	1,010	2,866	2,152
Canada	-	-	143	55	143	55
Total North America	1,507	1,142	1,502	1,065	3,009	2,207
Equatorial Guinea	45	29	173	122	218	151
Other Africa	12,909	2,108	2,580	510	15,489	2,618
Total Africa	12,954	2,137	2,753	632	15,707	2,769
Total Europe	131	68	1,765	1,050	1,896	1,118
Other International	-	-	3,628	2,022	3,628	2,022
WORLDWIDE	14,592	3,347	9,648	4,769	24,240	8,116

Oil Sands Mining

Through our acquisition of Western in 2007, we hold a 20 percent outside-operated interest in the AOSP, an oil sands mining joint venture located in Alberta, Canada. The joint venture produces bitumen from oil sands deposits in the Athabasca region utilizing mining techniques and upgrades the bitumen to synthetic crude oils and vacuum gas oil. The AOSP's mining and extractions assets are located near Fort McMurray, Alberta and include the Muskeg River mine which began bitumen production in 2003 and the Jackpine mine which is currently under construction and anticipated to commence bitumen production in the second half of 2010. The underlying developed leases are held for the duration of the project, with royalties payable to the province of Alberta. The upgrading assets are located at Fort Saskatchewan, northeast of Edmonton, Alberta. Additional upgrading capacity is being constructed with an anticipated startup in late 2010 or early 2011.

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 bitumen reserves increased 168 million barrels. See Item 1. Business – Reserves for comprehensive discussion of reserves related to our oil sands mining and conventional exploration and production operations. As of December 31, 2009, we have rights to participate in developed and undeveloped leases totaling approximately 215,000 gross (45,000 net) acres.

Current AOSP operations use established processes to mine oil sands deposits from an open-pit mine, extract the bitumen and upgrade it into synthetic crude oils. Ore is mined using traditional truck and shovel mining techniques. The mined ore passes through primary crushers to reduce the ore chunks in size and is then sent to rotary breakers where the ore chunks are further reduced to smaller particles. The particles are combined with hot water to create slurry. The slurry moves through the extraction process where it separates into sand, clay and bitumen-rich froth. A solvent is added to the bitumen froth to separate out the remaining solids, water and heavy asphaltenes. The solvent washes the sand and produces clean bitumen that is required for the upgrader to run efficiently. The process yields a mixture of solvent and bitumen which is then transported from the mine to the Scotford upgrader via the approximately 300 mile Corridor Pipeline.

The bitumen is upgraded at Scotford using both hydrotreating and hydroconversion processes to remove sulfur and break the heavy bitumen molecules into lighter products. Blendstocks acquired from outside sources are utilized in the production of our saleable products. The three major products that the Scotford upgrader produces are light synthetic crude oil, heavy synthetic crude oil and vacuum gas oil. The vacuum gas oil is sold to an affiliate of the operator under a long term contract at market-related prices, and the other products are sold in the marketplace.

Net synthetic crude oil sales were 32 mbpd in both 2009 and 2008, but were 4 mbpd in 2007. Daily volumes for 2007 represent total volumes since the acquisition date over total days in the period.

Prior to our acquisition of Western, the first fully integrated expansion of the existing AOSP facilities was approved in 2006. Expansion 1, which includes construction of mining and extraction facilities at the Jackpine mine, new treatment facilities at the existing Muskeg River mine, addition of a new processing train at the Scotford upgrading facility and development of related infrastructure, is on track and anticipated to begin mining operations in the second half of 2010, and upgrader operations in late 2010 or early 2011. When Expansion 1 is complete, we will have more than 50 mbpd of production and upgrading capacity in the Canadian oil sands. The timing and scope of potential future expansions and debottlenecking opportunities on existing operations remain under review.

The above discussion of the Oil Sands Mining segment includes forward-looking statements concerning the anticipated completion of AOSP Expansion 1 and the timing of production. Factors which could affect the expansion project 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. The AOSP expansion could be further affected by commissioning and start-up risks associated with prototype equipment and new technology.

Reserves

In December 2008, the Securities and Exchange Commission ("SEC") announced revisions to its regulations on oil and gas reporting. In January 2010, the Financial Accounting Standards Board issued an accounting standards update which was intended to harmonize the accounting literature with the SEC's new regulations. See Item 8. Financial Statements and Supplementary Data – Note 2 to the consolidated financial statements for a summary of the changes. The revised regulations were applied in estimating and reporting our reserves as of December 31, 2009, which totaled 1,679 mmboe.

Estimated Reserve Quantities

The following table sets forth estimated quantities of our net proved liquid hydrocarbon, natural gas and synthetic crude oil reserves based upon an unweighted average of closing prices for the first day of each month in the 12-month period ended December 31, 2009. Approximately 61 percent of our proved reserves are located in Organization for Economic Cooperation and Development ("OECD") countries.

Under the new regulations, reserves are now disclosed by continent, by country, if the proved reserves related to any geographic area, on an oil-equivalent barrel basis represent 15 percent or more of our total proved reserves. A geographic area can be an individual country, group of countries within a continent, or a continent. Reserve quantities previously reported for 2008 and 2007 have been reorganized into these geographic groupings below for comparability.

	North America			Africa			Europe	
December 31, 2009	United States	Canada	Total	EG	Other	Total	Total	Grand Total
Proved Developed Reserves								
Liquid hydrocarbon *(mmbbl)*	120	-	120	83	186	269	87	476
Natural gas *(bcf)*	652	-	652	1,102	107	1,209	50	1,911
Synthetic crude oil *(mmbbl)*	-	392	392	-	-	-	-	392
Total proved developed reserves *(mmboe)*	229	392	621	267	204	471	95	1,187
Proved Undeveloped Reserves								
Liquid hydrocarbon *(mmbbl)*	50	-	50	39	42	81	15	146
Natural gas *(bcf)*	168	-	168	586	-	586	59	813
Synthetic crude oil *(mmbbl)*	-	211	211	-	-	-	-	211
Total proved undeveloped reserves *(mmboe)*	78	211	289	136	42	178	25	492
Total Proved Reserves								
Liquid hydrocarbon *(mmbbl)*	170	-	170	122	228	350	102	622
Natural gas *(bcf)*	820	-	820	1,688	107	1,795	109	2,724
Synthetic crude oil *(mmbbl)*	-	603	603	-	-	-	-	603
Total proved reserves *(mmboe)*	307	603	910	403	246	649	120	1,679

The following table sets forth estimated quantities of our net proved liquid hydrocarbon and natural gas reserves based upon year end prices as of December 31, 2008 and 2007.

	North America			Africa			Europe		
December 31, 2008	United States	Canada[(a)]	Total	EG	Other	Total	Total	Disc. Ops.[(b)]	Grand Total
Proved Developed Reserves									
Liquid hydrocarbon *(mmbbl)*	137	-	137	99	193	292	81	4	514
Natural gas *(bcf)*	839	-	839	1,273	109	1,382	95	34	2,350
Total proved developed reserves *(mmboe)*	277	-	277	312	211	523	96	10	906
Total Proved Reserves									
Liquid hydrocarbon *(mmbbl)*	178	-	178	139	211	350	104	4	636
Natural gas *(bcf)*	1,085	-	1,085	1,866	109	1,975	159	132	3,351
Total proved reserves *(mmboe)*	359	-	359	450	229	679	131	26	1,195
Developed reserves as a percent of total proved reserves	77%	-	77%	69%	92%	77%	73%	38%	76%

December 31, 2007	North America United States	Canada[a]	Total	Africa EG	Other	Total	Europe Total	Disc. Ops.[b]	Grand Total
Proved Developed Reserves									
Liquid hydrocarbon *(mmbbl)*	135	-	135	113	183	296	32	8	471
Natural gas *(bcf)*	761	-	761	1,405	110	1,515	127	46	2,449
Total proved developed reserves *(mmboe)*	262	-	262	347	202	549	52	16	879
Total Proved Reserves									
Liquid hydrocarbon *(mmbbl)*	166	-	166	150	210	360	115	9	650
Natural gas *(bcf)*	1,007	-	1,007	1,951	110	2,061	238	144	3,450
Total proved reserves *(mmboe)*	334	-	334	475	228	703	155	33	1,225
Developed reserves as a percent of total proved reserves	78%	-	78%	73%	89%	78%	34%	48%	72%

(a) Before December 31, 2009, reserves related to oil sands mining were not included in the SEC's definition of oil and gas producing activities; therefore, these reserves are not reported for 2008 and 2007.

(b) Our businesses in Ireland and Gabon were sold in 2009. All periods have been recast to reflect these businesses as discontinued operations.

We previously reported OSM segment reserves as bitumen because oil sands mining was not considered an oil and gas producing activity by the SEC. Proved bitumen reserves reported as of December 31, 2008 and 2007 were 388 mmboe and 421 mmboe. December 31, 2009 reserve quantities under the new regulations include 603 mmboe of proved synthetic crude oil (bitumen after upgrading excluding blendstocks) related to our oil sands mining operations. While the change from bitumen to synthetic crude oil is responsible for some of the 2008 to 2009 increase in reported OSM segment reserves, the majority of the reserve increase is related to the three leases added to the Muskeg River mine in the second quarter of 2009. There were no other significant changes to our proved reserves in 2009.

The above estimated quantities of net proved liquid hydrocarbon and natural gas reserves are forward-looking statements and are based on a number of assumptions, including (among others) commodity prices, presently known physical data concerning size and character of the reservoirs, economic recoverability, technology developments, future drilling success, industry economic conditions, levels of cash flow from operations, production experience and other operating considerations. The above estimated quantities of synthetic crude oil reserves are forward-looking statements and are based on presently known physical data, economic recoverability and operating conditions. To the extent these assumptions prove inaccurate, actual recoveries and development costs could be different than current estimates. For additional details of the estimated quantities of proved reserves at the end of each of the last three years, see Item 8. Financial Statements and Supplementary Data—Supplementary Information on Oil and Gas Producing Activities.

Preparation of Reserve Estimates

Our estimation of net recoverable quantities of liquid hydrocarbons and natural gas is a highly technical process performed primarily by in-house teams of reservoir engineers and geoscience professionals. All estimates are made in compliance with SEC Rule 4-10 of Regulation S-X. Beginning December 31, 2009, reserve estimates are based upon the average of closing prices for the first day of each month in the 12-month period ended December 31, 2009. In previous periods, reserve estimates were based on prices at December 31.

Liquid hydrocarbon, natural gas and synthetic crude oil reserve estimates are reviewed and approved by our Corporate Reserves Group, which includes our Director of Corporate Reserves and her staff of Reserves Coordinators. Reserves estimates are developed and reviewed by Qualified Reserves Estimators ("QRE"). QRE are engineers or geoscientists with a minimum of a bachelor of science degree in the appropriate technical field, have a minimum of 3 years of industry experience with at least one year in reserve estimation and have completed Marathon's Qualified Reserve Estimator training course. The Reserve Coordinators review all reserves estimates for all fields with proved reserves greater than 3 million boe at a minimum of once every 3 years. Any change to proved reserve estimates in excess of 2.5 million boe on a total field basis, within a single month, must be approved by the Director of Corporate Reserves. All other proved reserve changes must be approved by a Reserve Coordinator.

Our Director of Corporate Reserves, who reports to our Chief Financial Officer, has a bachelor of science degree in petroleum engineering and a master of business administration. Her 35 years of experience in the industry include 24 with Marathon. She is active in industry and professional groups, having served on the Society of Petroleum Engineers ("SPE") Oil and Gas Reserves Committee ("OGRC") since 2004, chairing in 2008 and 2009. As a member of the OGRC, she participated in the development of the Petroleum Resource Management System ("PRMS") and served on the Technical Program Committee for a 2007 SPE Reserves Estimation Workshop: Sharing the Vision focusing on PRMS. She chaired the development of the OGRC comments on the SEC's proposed modernization of oil and gas reporting and was a member of the American Petroleum Institute's Ad Hoc group that provided comments on the same topic.

Estimates of synthetic crude oil reserves are prepared by GLJ Petroleum Consultants of Calgary, Canada, third-party consultants. A copy of their report is filed as Exhibit 99.1 to this Form 10-K. The engineer responsible for the estimates of our oil sands mining reserves has 31 years of experience in petroleum engineering and has conducted surface mineable oil sands evaluations since 1986. He is a member of SPE, having served as regional director 1998 through 2001 and is a registered Practicing Professional Engineer in the Province of Alberta.

Audits of Estimates

Third-party consultants are engaged to audit the in-house reserve estimates for fields that comprise the top 80 percent of our total proved reserves over a rolling four-year period. We met this goal for the four-year period ended December 31, 2009. We established a tolerance level of 10 percent for reserve audits such that initial estimates by the third-party consultants are accepted if they are within 10 percent of our internal estimates. Should the third-party consultants' initial analysis fail to reach our tolerance level, both our team and the consultants re-examine the information provided, request additional data and refine their analysis if appropriate. This resolution process is continued until both estimates are within 10 percent. This process did not result in significant changes to our reserve estimates in 2009, 2008, or 2007.

Netherland, Sewell and Associates, Inc. ("NSAI") prepared an independent estimate of December 31, 2008 reserves for Alba field. This reserve estimate was used by Corporate Reserves in much the same way third-party audits are now used. The NSAI summary report is filed as Exhibit 99.2 to this Form 10-K. The senior members of the NSAI team have over fifty years of industry experience between them, having worked for large, international oil and gas companies before joining NSAI. The team lead has a master of science in mechanical engineering and is a member of SPE. The senior technical advisor has a bachelor of science in geophysics and is a member of the Society of Exploration Geophysicists, the American Association of Petroleum Geologists and the European Association of Geoscientists and Engineers. Both are licensed in the state of Texas.

Ryder Scott Company ("Ryder Scott") performed audits of several of our fields in 2009. Their summary report on audits performed in 2009 is filed as Exhibit 99.3 to this Form 10-K. The team lead for Ryder Scott has over 18 years of industry experience, having worked for a major international oil and gas company before joining Ryder Scott. He has a bachelor of science in mechanical engineering, is a member of SPE and is a registered Professional Engineer in the state of Texas.

The Corporate Reserves Group may also perform separate, detailed technical reviews of reserve estimates for significant fields that were acquired recently or for properties with problematic indicators such as excessively long lives, sudden changes in performance or changes in economic or operating conditions.

Changes in Proved Undeveloped Reserves

As of December 31, 2009, 492 mmboe of proved undeveloped reserves were reported, an increase of 203 mmboe from December 31, 2008, primarily due to the inclusion of synthetic crude oil. Of the 492 mmboe of proved undeveloped reserves at year end 2009, 31 percent of the volume is associated with projects that have been included in proved reserves for more than five years. The majority of this volume is related to a compression project in Equatorial Guinea that was sanctioned by the Board of Directors in 2004 and is expected to be completed in 2014. There are no other significant undeveloped reserves expected to be developed more than five years from now. Projects can remain in proved undeveloped reserves for extended periods in many situations such as behind-pipe zones where reserves will not be accessed until the primary producing zone depletes, large development projects which take more than five years to complete, and the timing of when additional gas compression is needed. During 2009, we added 290 mmboe to proved undeveloped reserves and transferred 38 mmboe from proved undeveloped to proved developed reserves. Costs incurred for the periods ended December 31, 2009, 2008 and 2007 relating to the development of proved undeveloped reserves, were $792 million, $1,189 million and $1,250 million.

As of December 31, 2009, future development costs estimated to be required for the development of proved undeveloped liquid hydrocarbon, natural gas and synthetic crude oil reserves for the years 2010 through 2014 are projected to be $1,083 million, $565 million, $244 million, $331 million, and $123 million.

The above estimated future development costs relating to the development of proved undeveloped liquid hydrocarbon, natural gas and synthetic crude oil reserves are forward-looking statements and are based on a number of assumptions, including (among others) commodity prices, presently known physical data concerning size and character of the reservoirs, economic recoverability, technology developments, future drilling success, industry economic conditions, levels of cash flow from operations, production experience and other operating considerations. To the extent these assumptions prove inaccurate, actual recoveries and development costs could be different than current estimates.

Net Production Sold

	North America			Africa			Europe		
	United States	Canada[a]	Total	EG	Other	Total	Total	Disc. Ops[b]	Total
Year Ended December 31, 2009									
Liquid hydrocarbon *(mbpd)*[c]	64	-	64	42	45	87	92	5	248
Natural gas *(mmcfd)*[d][e]	373	-	373	426	4	430	116	17	936
Total production sold *(mboed)*	126	-	126	113	46	159	111	7	403
Year Ended December 31, 2008									
Liquid hydrocarbon *(mbpd)*[c]	63	-	63	40	47	87	55	6	211
Natural gas *(mmcfd)*[d][e]	448	-	448	366	4	370	129	37	984
Total production sold *(mboed)*	138	-	138	101	48	149	77	12	376
Year Ended December 31, 2007									
Liquid hydrocarbon *(mbpd)*[c]	64	-	64	45	45	90	33	10	197
Natural gas *(mmcfd)*[d][e]	477	-	477	227	5	232	130	39	878
Total production sold *(mboed)*	144	-	144	83	46	129	54	17	344

(a) Before December 31, 2009, reserves related to oil sands mining were not included in the SEC's definition of oil and gas producing activities; therefore, synthetic crude oil production of 27 mbpd is not reported for 2009.

(b) Our businesses in Ireland and Gabon were sold in 2009. All periods have been recast to reflect these businesses as discontinued operations.

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

(d) U.S. natural gas volumes exclude volumes produced in Alaska that are stored for later sale in response to seasonal demand, although our reserves have been reduced by those volumes.

(e) Excludes volumes acquired from third parties for injection and subsequent resale.

Average Sales Price per Unit

	North America			Africa			Europe		
(Dollars per unit)	United States	Canada[a]	Total	EG	Other	Total	Total	Disc. Ops[b]	Total
Year Ended December 31, 2009									
Liquid hydrocarbon *(bbl)*	$54.67	-	$54.67	$38.06	$ 68.41	$53.91	$64.46	$56.47	$58.06
Natural gas *(mcf)*	4.14	-	4.14	0.24	0.70	0.25	4.84	8.54	2.52
Year Ended December 31, 2008									
Liquid hydrocarbon *(bbl)*	86.68	-	86.68	66.34	110.49	89.85	90.60	96.41	89.29
Natural gas *(mcf)*	7.01	-	7.01	0.24	0.70	0.25	7.80	9.62	4.67
Year Ended December 31, 2007									
Liquid hydrocarbon *(bbl)*	60.15	-	60.15	50.10	80.57	65.41	70.31	72.19	64.86
Natural gas *(mcf)*	5.73	-	5.73	0.24	0.70	0.25	6.51	6.71	4.44

(a) Before December 31, 2009, oil sands mining was not included in the SEC's definition of oil and gas producing activities; therefore, synthetic crude oil prices are not reported.

(b) Our businesses in Ireland and Gabon were sold in 2009. All periods have been recast to reflect these businesses as discontinued operations.

Average Production Cost per Unit[a]

(Dollars per boe)	North America			Africa			Europe		
	United States	Canada[b]	Total	EG	Other	Total	Total	Disc. Ops[c]	Grand Total
Years ended December 31:									
2009	$14.03	-	$14.03	$2.63	$3.64	$2.93	$ 6.99	$19.14	$7.80
2008	12.82	-	12.82	2.57	2.39	2.51	11.72	15.24	8.61
2007	10.16	-	10.16	3.16	3.58	3.31	11.24	13.76	7.95

(a) Production, severance and property taxes are excluded from the production costs used in calculation of this metric.

(b) Before December 31, 2009, oil sands mining was not included in the SEC's definition of oil and gas producing activities; therefore, production costs are not reported.

(c) Our businesses in Ireland and Gabon were sold in 2009. All periods have been recast to reflect these businesses as discontinued operations.

Integrated Gas

Our integrated gas operations include natural gas liquefaction and regasification operations and methanol production operations. Also included in the financial results of the Integrated Gas segment are the costs associated with ongoing development of projects to link stranded natural gas resources with key demand areas.

We hold a 60 percent interest in EGHoldings, which is accounted for under the equity method of accounting. In May 2007, EGHoldings completed construction of a 3.7 million metric tonnes per annum ("mmtpa") LNG production facility on Bioko Island. LNG from the production facility is sold under a 3.4 mmtpa, or 460 mmcfd, sales and purchase agreement with a 17-year term. The purchaser under the agreement takes delivery of the LNG on Bioko Island, with pricing linked principally to the Henry Hub index, regardless of destination. This production facility allows us to monetize our natural gas reserves from the Alba field, as natural gas for the facility is purchased from the Alba field participants under a long-term natural gas supply agreement. Gross sales of LNG from this production facility totaled 3.9 million metric tonnes in 2009. In 2009, we continued discussions with the government of Equatorial Guinea and our partners regarding a potential second LNG production facility on Bioko Island.

We also own a 30 percent interest in a Kenai, Alaska, natural gas liquefaction plant, and lease two 87,500 cubic meter tankers used to transport LNG to customers in Japan. Feedstock for the plant is supplied from a portion of our natural gas production in the Cook Inlet. From the first production in 1969, we have sold our share of the LNG plant's production under long-term contracts with two of Japan's largest utility companies. In June 2008 we, along with our partner, received approval from the U.S. Department of Energy to extend the export license for this natural gas liquefaction plant through March 2011.

We own a 45 percent interest in AMPCO, which is accounted for under the equity method of accounting. AMPCO owns a methanol plant located in Malabo, Equatorial Guinea. Feedstock for the plant is supplied from our natural gas production from the Alba field. Gross sales of methanol from the plant totaled 960,374 metric tonnes in 2009. Production from the plant is used to supply customers in Europe and the United States.

In addition to our expertise in utilizing existing gas technologies to manufacture and market products such as LNG and methanol, we continue to conduct research to develop new leading-edge natural gas technologies. While existing known natural gas resources are much more abundant than the world's remaining oil resources, natural gas is more difficult to transport to global markets without the use of advanced gas technologies. Our Gas-to-Fuels ("GTF™") technology is one such promising technology.

Our GTF™ technology program is focused on converting natural gas into gasoline blendstocks and petrochemicals. Global markets for these products are significantly larger than the global markets for either LNG or methanol, further expanding the uses of natural gas. During 2009, we completed the initial run program of our newly-constructed GTF process demonstration unit, which was commissioned during 2008. This technology demonstration program has provided valuable information about materials of construction, process chemistry, and GTF plant operations.

During 2008, we entered into agreements with GRT, Inc., a Delaware corporation, to cooperate on the advancement of gas-to-fuels-related technology. This transaction provides us with access to additional specialized technical and research personnel and lab facilities, and significantly expanded the portfolio of patents available to us via license and through a cooperative development program. In addition, we have acquired a 20 percent interest in GRT, Inc.

The GTF™ technology is protected by an intellectual property protection program. The U.S. has granted 17 patents for the technology, with another 22 pending. Worldwide, there are over 300 patents issued or pending, covering over 100 countries including regional and direct foreign filings.

Another innovative technology that we are developing focuses on reducing the processing and transportation costs of natural gas by artificially creating natural gas hydrates, which are more easily transportable than natural gas in its gaseous form. Much like LNG, gas hydrates would then be regasified upon delivery to the receiving market. We have an active pilot program in place to test and further develop a proprietary natural gas hydrates manufacturing system.

The above discussion of the Integrated Gas segment contains forward-looking statements with respect to the possible expansion of the LNG production facility. Factors that could potentially affect the possible expansion of the LNG production facility include partner and government approvals, access to sufficient natural gas volumes through exploration or commercial negotiations with other resource owners and access to sufficient regasification capacity. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Refining, Marketing and Transportation

We have refining, marketing and transportation operations concentrated primarily in the Midwest, upper Great Plains, Gulf Coast and Southeast regions of the U.S. We rank as the fifth largest crude oil refiner in the U.S. and the largest in the Midwest. Our operations include a seven-plant refining network and an integrated terminal and transportation system which supplies wholesale and Marathon-brand customers as well as our own retail operations. Our wholly-owned retail marketing subsidiary Speedway SuperAmerica LLC ("SSA") is the third largest chain of company-owned and -operated retail gasoline and convenience stores in the U.S. and the largest in the Midwest.

Refining

We own and operate seven refineries with an aggregate refining capacity of 1.188 million barrels per day ("mmbpd") of crude oil as of December 31, 2009. During 2009, our refineries processed 957 mbpd of crude oil and 196 mbpd of other charge and blend stocks. The table below sets forth the location and daily crude oil refining capacity of each of our refineries as of December 31, 2009.

Crude Oil Refining Capacity

(Thousands of barrels per day)	2009
Garyville, Louisiana	436
Catlettsburg, Kentucky	212
Robinson, Illinois	206
Detroit, Michigan	106
Canton, Ohio	78
Texas City, Texas	76
St. Paul Park, Minnesota	74
TOTAL	1,188

Our refineries include crude oil atmospheric and vacuum distillation, fluid catalytic cracking, catalytic reforming, desulfurization and sulfur recovery units. The refineries process a wide variety of crude oils and produce numerous refined products, ranging from transportation fuels, such as reformulated gasolines, blend-grade gasolines intended for blending with fuel ethanol and ultra-low sulfur diesel fuel, to heavy fuel oil and asphalt. Additionally, we manufacture aromatics, cumene, propane, propylene, sulfur and maleic anhydride.

Our Garyville, Louisiana, refinery is located along the Mississippi River in southeastern Louisiana between New Orleans and Baton Rouge. The Garyville refinery predominantly processes heavy sour crude oil into products such as gasoline, distillates, sulfur, asphalt, propane, polymer grade propylene, isobutane and coke. Our Garyville refinery has earned designation as a U.S. Occupational Safety and Health Administration (OSHA) Voluntary Protection Program (VPP) STAR site.

The Garyville Major Expansion project, completed on schedule during the fourth quarter of 2009, is currently being fully integrated into the base Garyville refinery. As a result of the expansion, the refinery's crude oil refining capacity has grown from 256 mbpd to 436 mbpd, making it among the largest crude oil refineries in the country. The expansion also improves scale efficiencies, feedstock flexibility and refined product yields. The expansion project cost approximately $3.9 billion (excluding capitalized interest).

Our Catlettsburg, Kentucky, refinery is located in northeastern Kentucky on the western bank of the Big Sandy River, near the confluence with the Ohio River. The Catlettsburg refinery processes sweet and sour crude oils into products such as gasoline, asphalt, diesel, jet fuel, petrochemicals, propane, propylene and sulfur.

Our Robinson, Illinois, refinery is located in southeastern Illinois. The Robinson refinery processes sweet and sour crude oils into products such as multiple grades of gasoline, jet fuel, kerosene, diesel fuel, propane, propylene, sulfur and anode-grade coke. The Robinson refinery has earned designation as an OSHA VPP STAR site.

Our Detroit, Michigan, refinery is located near Interstate 75 in southwest Detroit. It is the only petroleum refinery currently operating in Michigan. The Detroit refinery processes light sweet and heavy sour crude oils, including Canadian crude oils, into products such as gasoline, diesel, asphalt, slurry, propane, chemical grade propylene and sulfur. In 2007, we approved a heavy oil upgrading and expansion project at this refinery, with a current projected cost of $2.2 billion (excluding capitalized interest). This project will enable the refinery to process an additional 80 mbpd of heavy sour crude oils, including Canadian bitumen blends, and will increase its crude oil refining capacity by about 10 percent. Construction began in the first half of 2008 and is presently expected to be complete in the second half of 2012. Our Detroit refinery is certified as a Michigan VPP site, receiving Rising Star status, and expects to satisfy the requirements for STAR status in the first quarter of 2010.

Our Canton, Ohio, refinery is located approximately 60 miles southeast of Cleveland, Ohio. The Canton refinery processes sweet and sour crude oils into products such as gasoline, diesel fuels, kerosene, propane, sulfur, asphalt, roofing flux, home heating oil and No. 6 industrial fuel oil.

Our Texas City, Texas, refinery is located on the Texas gulf coast approximately 30 miles south of Houston, Texas. The refinery processes sweet crude oil into products such as gasoline, propane, chemical grade propylene, slurry, sulfur and aromatics.

Our St. Paul Park, Minnesota, refinery is located in southeastern Minnesota where it is one of only two refineries in the state. The St. Paul Park refinery processes predominantly Canadian crude oils into products such as gasoline, diesel, jet fuel, kerosene, asphalt, propane, propylene and sulfur. Our St. Paul Park refinery is certified as a Minnesota VPP site, receiving Rising Star status, and expects to satisfy the requirements for STAR status in 2010.

The above discussion includes forward-looking statements concerning the Detroit refinery heavy oil upgrading and expansion project. Some factors that could affect this project 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.

Our refineries are integrated with each other via pipelines, terminals and barges to maximize operating efficiency. The transportation links that connect our refineries allow the movement of crude oil, feedstocks and intermediate products between refineries to optimize operations, produce higher margin products and utilize our processing capacity efficiently.

The following table sets forth our refinery production by product group for each of the last three years.

Refined Product Yields

(Thousands of barrels per day)	2009	2008	2007
Gasoline	669	609	646
Distillates	326	342	349
Propane	23	22	23
Feedstocks and special products	62	96	108
Heavy fuel oil	24	24	27
Asphalt	66	75	86
TOTAL	1,170	1,168	1,239

Planned maintenance activities, or turnarounds, requiring temporary shutdown of certain refinery operating units, are periodically performed at each refinery. In recent years, planned turnarounds have occurred at two or three refineries per year.

Crude oil supply – We obtain most of the crude oil we refine through negotiated contracts and purchases or exchanges on the spot market. Our crude oil supply contracts are generally term contracts with market related pricing provisions. The following table provides information on our sources of crude oil for each of the last three years. The crude oil sourced outside of North America was acquired from various foreign national oil companies, producing companies and trading companies. Of the U.S. and Canadian sourced crude processed at our refineries, 33 mbpd, or four percent, was supplied by a combination of our E&P and OSM production operations for the year 2009.

Sources of Crude Oil Refined

(Thousands of barrels per day)	2009	2008	2007
United States	613	466	527
Canada	136	135	138
Middle East and Africa	154	244	253
Other international	54	99	92
TOTAL	957	944	1,010
Average cost of crude oil throughput (Dollars per barrel)	$62.10	$98.34	$71.20

Our refineries receive crude oil and other feedstocks and distribute our refined products through a variety of channels, including pipelines, trucks, railcars, ships and barges.

Refined products marketing and distribution – We are a supplier of refined products to resellers and consumers within our 24-state market area in the Midwest, upper Great Plains, Gulf Coast and southeastern regions of the United States. Our market area includes approximately 4,600 Marathon branded-retail outlets concentrated in the Midwest and southeastern states. We currently own and distribute from 64 light product and 22 asphalt terminals. In addition, we distribute through 60 third-party terminals in our market area. Our marine transportation operations include 16 towboats, as well as 183 owned and 8 leased barges that transport refined products on the Ohio, Mississippi and Illinois rivers and their tributaries as well as the Intercoastal Waterway. We lease or own approximately 2,400 railcars of various sizes and capacities for movement and storage of refined products. In addition, we own over 120 transport trucks for the movement of light products.

The following table sets forth, as a percentage of total refined product sales, sales of refined products to our different customer types for the past three years.

Refined Product Sales by Customer Type	2009	2008	2007
Private-brand marketers, commercial and industrial consumers	67%	67%	69%
Marathon-branded outlets	18%	18%	16%
Speedway SuperAmerica LLC retail outlets	15%	15%	15%

The following table sets forth our refined products sales by product group and our average sales price for each of the last three years.

Refined Product Sales

(Thousands of barrels per day)	2009	2008	2007
Gasoline	830	756	791
Distillates	357	375	377
Propane	23	22	23
Feedstocks and special products	75	100	103
Heavy fuel oil	24	23	29
Asphalt	69	76	87
TOTAL	1,378	1,352	1,410
Average sales price (Dollars per barrel)	$70.86	$109.49	$86.53

We sell gasoline, gasoline blendstocks and No. 1 and No. 2 fuel oils (including kerosene, jet fuel and diesel fuel) to wholesale marketing customers in the Midwest, upper Great Plains, Gulf Coast and southeastern regions of the United States. We sold 51 percent of our gasoline volumes and 87 percent of our distillates volumes on a wholesale or spot market basis in 2009. The demand for gasoline is seasonal in many of our markets, with demand typically being at its highest levels during the summer months.

We have blended ethanol into gasoline for over 20 years and began expanding our blending program in 2007, in part due to federal regulations that require us to use specified volumes of renewable fuels. Ethanol volumes sold in blended gasoline were 60 mbpd in 2009, 54 mbpd in 2008 and 40 mbpd in 2007. The future expansion or contraction of our ethanol blending program will be driven by the economics of the ethanol supply and by government regulations. We sell reformulated gasoline, which is also blended with ethanol, in parts of our marketing territory, including: Chicago, Illinois; Louisville, Kentucky; northern Kentucky; Milwaukee, Wisconsin, and Hartford, Illinois. We also sell biodiesel-blended diesel in Minnesota, Illinois and Kentucky.

We produce propane at all seven of our refineries. Propane is primarily used for home heating and cooking, as a feedstock within the petrochemical industry, for grain drying and as a fuel for trucks and other vehicles. Our propane sales are typically split evenly between the home heating market and industrial consumers.

We are a producer and marketer of petrochemicals and specialty products. Product availability varies by refinery and includes benzene, cumene, dilute naphthalene oil, molten maleic anhydride, molten sulfur, propylene, toluene and xylene. We market propylene, cumene and sulfur domestically to customers in the chemical industry. We sell maleic anhydride throughout the United States and Canada. We also have the capacity to produce 1,400 tons per day of anode grade coke at our Robinson refinery, which is used to make carbon anodes for the aluminum smelting industry, and 5,500 tons per day of fuel grade coke at the Garyville refinery, which is used for power generation and in miscellaneous industrial applications. In early 2009, we discontinued production and sales of petroleum pitch and aliphatic solvents at our Catlettsburg refinery.

We produce and market heavy residual fuel oil or related components at all seven of our refineries. Another product of crude oil, heavy residual fuel oil, is primarily used in the utility and ship bunkering (fuel) industries, though there are other more specialized uses of the product.

We have refinery based asphalt production capacity of up to 108 mbpd. We market asphalt through 33 owned or leased terminals throughout the Midwest and Southeast. We have a broad customer base, including approximately 675 asphalt-paving contractors, government entities (states, counties, cities and townships) and asphalt roofing shingle manufacturers. We sell asphalt in the wholesale and cargo markets via rail and barge. We also produce asphalt cements, polymer modified asphalt, emulsified asphalt and industrial asphalts.

In 2007, we acquired a 35 percent interest in an entity which owns and operates a 110-million-gallon-per-year ethanol production facility in Clymers, Indiana. We also own a 50 percent interest in an entity which owns a 110-million-gallon-per-year ethanol production facility in Greenville, Ohio. The Greenville plant began production in February 2008. Both of these facilities are managed by a co-owner.

Pipeline transportation – We own a system of pipelines through Marathon Pipe Line LLC ("MPL") and Ohio River Pipe Line LLC ("ORPL"), our wholly-owned subsidiaries. Our pipeline systems transport crude oil and refined products primarily in the Midwest and Gulf Coast regions to our refineries, our terminals and other pipeline systems. Our MPL and ORPL wholly-owned and undivided interest common carrier systems consist of 1,737 miles of crude oil lines and 1,825 miles of refined product lines comprising 32 systems located in 11 states. The MPL common carrier pipeline network is one of the largest petroleum pipeline systems in the United States, based on total barrels delivered. Our common carrier pipeline systems are subject to state and Federal Energy Regulatory Commission regulations and guidelines, including published tariffs for the transportation of crude oil and refined products. Third parties generated 13 percent of the crude oil and refined product shipments on our MPL and ORPL common carrier pipelines in 2009. Our MPL and ORPL common carrier pipelines transported the volumes shown in the following table for each of the last three years.

Pipeline Barrels Handled

(Thousands of barrels per day)	2009	2008	2007
Crude oil trunk lines	1,279	1,405	1,451
Refined products trunk lines	953	960	1,049
TOTAL	2,232	2,365	2,500

We also own 196 miles of private crude oil pipelines and 850 miles of private refined products pipelines, and we lease 217 miles of common carrier refined product pipelines. We have partial ownership interests in several pipeline companies that have approximately 780 miles of crude oil pipelines and 3,600 miles of refined products pipelines, including about 970 miles operated by MPL. In addition, MPL operates most of our private pipelines and 985 miles of crude oil and 160 miles of natural gas pipelines owned by our E&P segment.

Our major refined product pipelines include the owned and operated Cardinal Products Pipeline and the Wabash Pipeline. The Cardinal Products Pipeline delivers refined products from Kenova, West Virginia, to Columbus, Ohio. The Wabash Pipeline system delivers product from Robinson, Illinois, to various terminals in the area of Chicago, Illinois. Other significant refined product pipelines owned and operated by MPL extend from: Robinson, Illinois, to Louisville, Kentucky; Garyville, Louisiana, to Zachary, Louisiana; and Texas City, Texas, to Pasadena, Texas.

In addition, as of December 31, 2009, we had interests in the following refined product pipelines:

- 65 percent undivided ownership interest in the Louisville-Lexington system, a petroleum products pipeline system extending from Louisville to Lexington, Kentucky;
- 60 percent interest in Muskegon Pipeline LLC, which owns a refined products pipeline extending from Griffith, Indiana, to North Muskegon, Michigan;
- 50 percent interest in Centennial Pipeline LLC, which owns a refined products system connecting the Gulf Coast region with the Midwest market;
- 17 percent interest in Explorer Pipeline Company, a refined products pipeline system extending from the Gulf Coast to the Midwest; and
- 6 percent interest in Wolverine Pipe Line Company, a refined products pipeline system extending from Chicago, Illinois, to Toledo, Ohio.

Our major owned and operated crude oil lines run from: Patoka, Illinois, to Catlettsburg, Kentucky; Patoka, Illinois, to Robinson, Illinois; Patoka, Illinois, to Lima, Ohio; Lima, Ohio to Canton, Ohio; Samaria, Michigan, to Detroit, Michigan; and St. James, Louisiana, to Garyville, Louisiana.

As of December 31, 2009, we had interests in the following crude oil pipelines:

- 51 percent interest in LOOP LLC, the owner and operator of LOOP, which is the only U.S. deepwater oil port, located 18 miles off the coast of Louisiana, and a crude oil pipeline connecting the port facility to storage caverns and tanks at Clovelly, Louisiana;
- 59 percent interest in LOCAP LLC, which owns a crude oil pipeline connecting LOOP and the Capline system;

- 33 percent undivided joint interest in the Capline system, a large-diameter crude oil pipeline extending from St. James, Louisiana, to Patoka, Illinois;
- 26 percent undivided joint interest in the Maumee Pipeline System, a large diameter crude oil pipeline extending from Lima, Ohio, to Samaria, Michigan; and
- 17 percent interest in Minnesota Pipe Line Company, LLC, which owns crude oil pipelines extending from Clearbrook, Minnesota, to Cottage Grove, Minnesota, which is in the vicinity of our St. Paul Park, Minnesota refinery.

We plan to construct, by the year 2012, a new section of pipeline connecting with the existing crude line from Samaria, Michigan, to Detroit, Michigan. This new section will deliver additional supplies of Canadian crude to our Detroit refinery.

The above discussion includes forward-looking statements concerning the construction of a new section of pipeline in Michigan. Some factors that could affect this project include transportation logistics, availability of materials and labor, unforeseen hazards such as weather conditions, delays in obtaining or conditions imposed by government or third-party approvals and other risks customarily associated with construction projects.

Retail Marketing

SSA, our wholly-owned subsidiary headquartered in Enon, Ohio, sells gasoline and merchandise through owned and operated retail outlets primarily under the Speedway® and SuperAmerica® brands. Diesel fuel is also sold at a number of these outlets. SSA retail outlets offer a wide variety of merchandise, such as prepared foods, beverages, and non-food items, as well as a significant number of proprietary items. For eight consecutive quarters, SSA has been rated as the best convenience store chain in terms of overall customer satisfaction in a national consumer perception survey conducted by Corporate Research International®. In 2009, Harris Interactive's EquiTrend® annual brand equity study named Speedway® the number one gasoline brand with consumers. SSA's Speedy Rewards™, an industry-leading customer loyalty program, has built active membership to 3.2 million customers.

As of December 31, 2009, SSA had 1,603 retail outlets in nine states. Sales of refined products through these retail outlets accounted for 15 percent of our refined product sales volumes in 2009 and provide us with a base of ratable sales. Revenues from sales of non-petroleum merchandise through these retail outlets totaled $3,109 million in 2009, $2,838 million in 2008 and $2,796 million in 2007. The demand for gasoline is seasonal in a majority of SSA markets, with the highest demand usually occurring during the summer driving season. Margins from the sale of merchandise and services tend to be less volatile than margins from the retail sale of gasoline and diesel fuel.

Competition and Market Conditions

Strong competition exists in all sectors of the oil and gas industry and, in particular, in the exploration for and development of new reserves. We compete with major integrated and independent oil and gas companies, as well as national oil companies, for the acquisition of oil and natural gas leases and other properties. We compete with these companies for the equipment and labor required to develop and operate those properties and in the marketing of oil and natural gas to end-users. Many of our competitors have financial and other resources greater than those available to us. Acquiring the more attractive exploration opportunities frequently requires competitive bids involving front-end bonus payments or commitments-to-work programs. We also compete in attracting and retaining personnel, including geologists, geophysicists and other specialists. Based upon statistics compiled in the "2009 Global Upstream Performance Review" published by IHS Herold Inc., we rank eighth among U.S.-based petroleum companies on the basis of 2008 worldwide liquid hydrocarbon and natural gas production.

We also compete with other producers of synthetic and conventional crude oil for the sale of our synthetic crude oil to refineries primarily in North America. There are several additional synthetic crude oil projects being contemplated by various competitors and, if undertaken and completed, these projects may result in a significant increase in the supply of synthetic crude oil to the market. Since not all refineries are able to process or refine synthetic crude oil in significant volumes, there can be no assurance that sufficient market demand will exist at all times to absorb our share of the synthetic crude oil production from the AOSP at economically viable prices.

We must also compete with a large number of other companies to acquire crude oil for refinery processing and in the distribution and marketing of a full array of petroleum products. Based upon the "The Oil & Gas Journal

2010 Worldwide Refinery Survey", we rank fifth among U.S. petroleum companies on the basis of U.S. crude oil refining capacity as of December 31, 2009. We compete in four distinct markets for the sale of refined products – wholesale, spot, branded and retail distribution. We believe we compete with about 64 companies in the sale of refined products to wholesale marketing customers, including private-brand marketers and large commercial and industrial consumers; about 75 companies in the sale of refined products in the spot market; ten refiners or marketers in the supply of refined products to refiner branded jobbers and dealers; and approximately 290 retailers in the retail sale of refined products. (A jobber is a business that does not carry out refining operations but supplies refiner-branded products to gasoline stations or convenience stores. Dealers refer to retail service station or convenience store operators affiliated with a brand identity.) We compete in the convenience store industry through SSA's retail outlets. The retail outlets offer consumers gasoline, diesel fuel (at selected locations) and a broad mix of other merchandise and services. Several nontraditional fuel retailers, such as supermarkets, club stores and mass merchants, have affected the convenience store industry and the National Petroleum News estimates such retailers had 11 percent of the U.S. gasoline market in 2009.

Our operating results are affected by price changes in conventional and synthetic crude oil, natural gas and petroleum products, as well as changes in competitive conditions in the markets we serve. Generally, results from production and oil sands mining operations benefit from higher crude oil prices while the refining and wholesale marketing gross margin may be adversely affected by crude oil price increases. Price differentials between sweet and sour crude oil also affect operating results. Market conditions in the oil and gas industry are cyclical and subject to global economic and political events and new and changing governmental regulations.

Environmental Matters

The Public Policy Committee of our Board of Directors is responsible for overseeing our position on public issues, including environmental matters. Our Corporate Health, Environment, Safety and Security organization has the responsibility to ensure that our operating organizations maintain environmental compliance systems that support and foster our compliance with applicable laws and regulations. Committees comprised of certain of our officers review our overall performance associated with various environmental compliance programs. We also have a Crisis Management Team which oversees our response to any major environmental or other emergency incident involving us or any of our properties.

State, national and international legislation to reduce greenhouse gas emissions are being proposed and, in some cases, promulgated. This legislation applies or could apply in countries in which we operate. Potential legislation and regulations pertaining to climate change could also affect our operations. The cost to comply with these laws and regulations cannot be estimated at this time, but could be significant. For additional information, see Item 1A. Risk Factors. As part of our commitment to environmental stewardship, we estimate and publicly report greenhouse gas emissions from our operations. We are working to continuously improve the accuracy and completeness of these estimates. In addition, we continuously strive to improve operational and energy efficiencies through resource and energy conservation where practicable and cost effective.

Our businesses are also subject to numerous other laws and regulations relating to the protection of the environment. These environmental laws and regulations include the Clean Air Act ("CAA") with respect to air emissions, the Clean Water Act ("CWA") with respect to water discharges, the Resource Conservation and Recovery Act ("RCRA") with respect to solid and hazardous waste treatment, storage and disposal, the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA") with respect to releases and remediation of hazardous substances and the Oil Pollution Act of 1990 ("OPA-90") with respect to oil pollution and response. In addition, many states where we operate have their own similar laws dealing with similar matters. New laws are being enacted, and regulations are being adopted by various regulatory agencies on a continuing basis and the costs of compliance with these new rules can only be broadly appraised until their implementation becomes more accurately defined. In some cases, they can impose liability for the entire cost of clean-up on any responsible party without regard to negligence or fault and impose liability on us for the conduct of others or conditions others have caused, or for our acts that complied with all applicable requirements when we performed them. The ultimate impact of complying with existing laws and regulations is not clearly known or determinable because certain implementing regulations for some environmental laws have not yet been finalized or, in some instances, are undergoing revision. These environmental laws and regulations, particularly the 1990 Amendments to the CAA and its implementing regulations, new water quality requirements and stricter fuel regulations, could result in increased capital, operating and compliance costs.

For a discussion of environmental capital expenditures and costs of compliance for air, water, solid waste and remediation, see Item 3. Legal Proceedings and Item 7. Management's Discussion and Analysis of Financial

Condition and Results of Operations – Management's Discussion and Analysis of Environmental Matters, Litigation and Contingencies.

Air

The EPA is in the process of implementing regulations to address the National Ambient Air Quality Standards ("NAAQS") for fine particulate emissions and ozone. In connection with these standards, the EPA will designate certain areas as "nonattainment," meaning that the air quality in such areas does not meet the NAAQS. To address these nonattainment areas, the EPA proposed a rule in 2004 called the Interstate Air Quality Rule ("IAQR") that would require significant emissions reductions in numerous states. The final rule, promulgated in 2005, was renamed the Clean Air Interstate Rule ("CAIR"). While the EPA expects that states will meet their CAIR obligations by requiring emissions reductions from electric generating units, states were to have the final say on what sources they regulate to meet attainment criteria. Significant uncertainty in the final requirements of this rule resulted from litigation (State of North Carolina, et al. v. EPA). In July 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated the CAIR in its entirety and remanded it to EPA to promulgate a rule consistent with the Court's opinion. In December 2008, the Court modified its July ruling to leave the CAIR in effect until EPA develops a new rule and control program. The EPA has announced that it plans to propose a new Clean Air Transport Rule in July of 2010. It is expected that the CAIR will be significantly altered, and it could result in changes in emissions control strategies. Our refinery operations are located in affected states, and some of these states may choose to propose more stringent fuels requirements on our refineries in order to meet the CAIR. We cannot reasonably estimate the final financial impact of the state actions to implement the CAIR until the EPA has issued a revised rule and states have taken further action to implement that rule.

The EPA is reviewing and is proposing to revise, all NAAQS for criteria air pollutants. The EPA promulgated a revised ozone standard in March 2008, and commenced the multi-year process to develop the implementing rules required by the Clean Air Act. On September 16, 2009, the EPA announced that they would reconsider the level of the ozone standard. By court order a final rule is to be signed by August 31, 2010. Also, on July 15, 2009, the EPA proposed a new short-term nitrogen dioxide standard. The final standard was issued January 22, 2010. In addition, on December 8, 2009, the EPA proposed a new short term standard for sulfur dioxide. This final standard is to be issued no later than June 2, 2010. We cannot reasonably estimate the final financial impact of these revised NAAQS standard until the implementing rules are established and judicial challenges over the revised NAAQS standards are resolved.

Water

We maintain numerous discharge permits as required under the National Pollutant Discharge Elimination System program of the CWA and have implemented systems to oversee our compliance efforts. In addition, we are regulated under OPA-90, which amended the CWA. Among other requirements, OPA-90 requires the owner or operator of a tank vessel or a facility to maintain an emergency plan to respond to releases of oil or hazardous substances. Also, in case of any such release, OPA-90 requires the responsible company to pay resulting removal costs and damages. OPA-90 also provides for civil penalties and imposes criminal sanctions for violations of its provisions.

Additionally, OPA-90 requires that new tank vessels entering or operating in U.S. waters be double-hulled and that existing tank vessels that are not double-hulled be retrofitted or removed from U.S. service, according to a phase-out schedule. All of the barges used for river transport of our raw materials and refined products meet the double-hulled requirements of OPA-90. We operate facilities at which spills of oil and hazardous substances could occur. Some coastal states in which we operate have passed state laws similar to OPA-90, but with expanded liability provisions, including provisions for cargo owner responsibility as well as ship owner and operator responsibility. We have implemented emergency oil response plans for all of our components and facilities covered by OPA-90, and we have established Spill Prevention, Control and Countermeasures ("SPCC") plans for facilities subject to CWA SPCC requirements.

Solid Waste

We continue to seek methods to minimize the generation of hazardous wastes in our operations. The Resource Conservation and Recovery Act ("RCRA") establishes standards for the management of solid and hazardous wastes. Besides affecting waste disposal practices, RCRA also addresses the environmental effects of certain past waste disposal operations, the recycling of wastes and the regulation of underground storage tanks ("USTs") containing regulated substances. We have ongoing RCRA treatment and disposal operations at one of our RM&T facilities and primarily utilize offsite third-party treatment and disposal facilities. In 2010, Canada will implement a ban on the land application of certain wastes. However, the ongoing waste handling and disposal-related costs associated with the Canadian land disposal restrictions are not material because we have identified alternative hazardous waste treatment options within the United States.

Remediation

We own or operate certain retail outlets where, during the normal course of operations, releases of refined products from USTs have occurred. Federal and state laws require that contamination caused by such releases at these sites be assessed and remediated to meet applicable standards. The enforcement of the UST regulations under RCRA has been delegated to the states, which administer their own UST programs. Our obligation to remediate such contamination varies, depending on the extent of the releases and the stringency of the laws and regulations of the states in which we operate. A portion of these remediation costs may be recoverable from the appropriate state UST reimbursement funds once the applicable deductibles have been satisfied. We also have other facilities which are subject to remediation under federal or state law. See Item 3. Legal Proceedings – Environmental Proceedings – Other Proceedings for a discussion of these sites.

The AOSP operations use established processes to mine deposits of bitumen from an open-pit mine, extract the bitumen and upgrade it into synthetic crude oils. Tailings are waste products created from the oil sands extraction process which are placed in ponds. The AOSP is required to reclaim its tailing ponds as part of its on going reclamation work. The reclamation process uses developing technology and there is an inherent risk that the current process may not be as effective or perform as required in order to meet the approved closure and reclamation plan. The AOSP continues to develop its current reclamation technology and continues to investigate other alternate tailings management technologies. In February 2009, the Alberta Energy Resources Conservation Board ("ERCB") issued a directive which more clearly defines criteria for managing oil sands tailings. In September 2009, the AOSP Joint Venture Operator submitted a tailings management paper to the ERCB, that sets forth its plan to comply with the Directive. This plan is currently under review by the ERCB. Increased compliance costs may result if tailing pond reclamation technologies prove unsuccessful or less effective than anticipated.

Other Matters

In 2007, the U.S. Congress passed the Energy Independence and Security Act ("EISA"), which, among other things, sets a target of 35 miles per gallon for the combined fleet of cars and light trucks in the United States by model year 2020, and contains a second Renewable Fuel Standard ("RFS2"). The EPA announced the final RFS2 regulations on February 4, 2010. The RFS2 requires 12.95 billion gallons of renewable fuel usage in 2010, increasing to 36.0 billion gallons by 2022. In the near term, the RFS2 will be satisfied primarily with fuel ethanol blended into gasoline. The RFS2 presents production and logistic challenges for both the fuel ethanol and petroleum refining industries. The RFS2 has required, and will likely in the future continue to require, additional capital expenditures or expenses by us to accommodate increased fuel ethanol use. Within the overall 36.0 billion gallon RFS2, EISA establishes an advanced biofuel RFS2 that begins with 0.95 billion gallons in 2010 and increases to 21.0 billion gallons by 2022. Subsets within the advanced biofuel RFS2 include 1.15 billion gallons of biomass-based diesel in 2010, increasing to 1.0 billion gallons in 2012, and 0.1 billion gallons of cellulosic biofuel in 2010, increasing to 16.0 billion gallons by 2022. The EPA has determined that 0.1 billion gallons of cellulosic biofuel will not be produced in 2010 and has lowered the requirement to 5.0 million gallons. The advanced biofuels programs will present specific challenges in that we may have to enter into arrangements with other parties to meet our obligations to use advanced biofuels, including biomass-based diesel and cellulosic biofuel, with potentially uncertain supplies of these new fuels. There will be compliance costs and uncertainties regarding how we will comply with the various requirements contained in this law and related regulations. We may experience a decrease in demand for refined petroleum products due to an increase in combined fleet mileage or due to refined petroleum products being replaced by renewable fuels.

The USX Separation

On December 31, 2001, pursuant to an Agreement and Plan of Reorganization dated as of July 31, 2001, Marathon completed the USX Separation, in which:

- its wholly-owned subsidiary United States Steel LLC converted into a Delaware corporation named United States Steel Corporation and became a separate, publicly traded company; and
- USX Corporation changed its name to Marathon Oil Corporation.

As a result of the USX Separation, Marathon and United States Steel are separate companies and neither has any ownership interest in the other.

In connection with the USX Separation and pursuant to the Plan of Reorganization, Marathon and United States Steel have entered into a series of agreements governing their relationship after the USX Separation and providing for the allocation of tax and certain other liabilities and obligations arising from periods before the USX Separation. The following is a description of the material terms of one of those agreements.

Financial Matters Agreement

Under the financial matters agreement, United States Steel has assumed and agreed to discharge all of our principal repayment, interest payment and other obligations under the following, including any amounts due on any default or acceleration of any of those obligations, other than any default caused by us:

- obligations under industrial revenue bonds related to environmental projects for current and former U.S. Steel Group facilities, with maturities ranging from 2011 through 2033;
- sale-leaseback financing obligations under a lease for equipment at United States Steel's Fairfield Works facility, with a lease term to 2012, subject to extensions;
- obligations relating to various lease arrangements accounted for as operating leases and various guarantee arrangements, all of which were assumed by United States Steel; and
- certain other guarantees.

The financial matters agreement also provides that, on or before the tenth anniversary of the USX Separation, United States Steel will provide for our discharge from any remaining liability under any of the assumed industrial revenue bonds. United States Steel may accomplish that discharge by refinancing or, to the extent not refinanced, paying us an amount equal to the remaining principal amount of all accrued and unpaid debt service outstanding on, and any premium required to immediately retire, the then outstanding industrial revenue bonds.

Under the financial matters agreement, United States Steel has all of the existing contractual rights under the leases assumed from us, including all rights related to purchase options, prepayments or the grant or release of security interests. However, United States Steel has no right to increase amounts due under or lengthen the term of any of the assumed lease obligations without our prior consent other than extensions set forth in the terms of the assumed leases.

The financial matters agreement requires us to use commercially reasonable efforts to assure compliance with all covenants and other obligations to avoid the occurrence of a default or the acceleration of the payments on the assumed obligations.

United States Steel's obligations to us under the financial matters agreement are general unsecured obligations that rank equal to United States Steel's accounts payable and other general unsecured obligations. The financial matters agreement does not contain any financial covenants and United States Steel is free to incur additional debt, grant mortgages on or security interests in its property and sell or transfer assets without our consent.

Concentrations of Credit Risk

We are exposed to credit risk in the event of nonpayment by counterparties, a significant portion of which are concentrated in energy-related industries. The creditworthiness of customers and other counterparties is subject to continuing review, including the use of master netting agreements, where appropriate. While no single customer accounts for more than 10 percent of annual revenues, we have exposures to United States Steel arising from the transaction discussed in Note 3 to the consolidated financial statements.

Trademarks, Patents and Licenses

We currently hold a number of U.S. and foreign patents and have various pending patent applications. Although in the aggregate our trademarks, patents and licenses are important to us, we do not regard any single trademark, patent, license or group of related trademarks, patents or licenses as critical or essential to our business as a whole.

Employees

We had 28,855 active employees as of December 31, 2009. Of that number, 18,325 were employees of SSA, most of who were employed at our retail marketing outlets.

Certain hourly employees at our Catlettsburg and Canton refineries are represented by the United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers Union under labor agreements that expire on January 31, 2012. Certain employees at our Texas City refinery are represented by the same union under a labor agreement that expires on March 31, 2012. The International Brotherhood of Teamsters represents certain hourly employees under labor agreements that are scheduled to expire on May 31, 2012 at our St. Paul Park refinery and January 31, 2011, at our Detroit refinery.

Executive Officers of the Registrant

The executive officers of Marathon and their ages as of February 1, 2010, are as follows:

Clarence P. Cazalot, Jr.	59	President and Chief Executive Officer
Janet F. Clark	55	Executive Vice President and Chief Financial Officer
Gary R. Heminger	56	Executive Vice President, Downstream
Jerry Howard	61	Senior Vice President, Corporate Affairs
Sylvia J. Kerrigan	44	Vice President, General Counsel and Secretary
Paul C. Reinbolt	54	Vice President, Finance and Treasurer
David E. Roberts, Jr.	49	Executive Vice President, Upstream
Michael K. Stewart	52	Vice President, Accounting and Controller
Howard J. Thill	50	Vice President, Investor Relations and Public Affairs

With the exception of Mr. Roberts, all of the executive officers have held responsible management or professional positions with Marathon or its subsidiaries for more than the past five years.

- Mr. Cazalot was appointed president and chief executive officer effective January 2002.
- Ms. Clark was appointed executive vice president effective January 2007. Ms. Clark joined Marathon in January 2004 as senior vice president and chief financial officer.
- Mr. Heminger was appointed executive vice president, downstream effective July 2005. Mr. Heminger has served as president of MPC since September 2001.
- Mr. Howard was appointed senior vice president, corporate affairs effective January 2002.
- Ms. Kerrigan was appointed vice president, general counsel and secretary effective November 1, 2009. Prior to this appointment, Ms. Kerrigan was assistant general counsel since January 1, 2003.
- Mr. Reinbolt was appointed vice president, finance and treasurer effective January 2002.
- Mr. Roberts joined Marathon in June 2006 as senior vice president, business development and was appointed executive vice president, upstream in April 2008. Prior to joining Marathon, he was employed by BG Group from 2003 as executive vice president/managing director responsible for Asia and the Middle East.
- Mr. Stewart was appointed vice president, accounting and controller effective May 2006. Mr. Stewart previously served as controller from July 2005 to April 2006. Prior to his appointment as controller, Mr. Stewart was director of internal audit from January 2002 to June 2005.
- Mr. Thill was appointed vice president, investor relations and public affairs effective January 2008. Mr. Thill was previously director of investor relations from April 2003 to December 2007.

Available Information

General information about Marathon, including the Corporate Governance Principles and Charters for the Audit and Finance Committee, Compensation Committee, Corporate Governance and Nominating Committee and

Public Policy Committee, can be found at www.marathon.com. In addition, our Code of Business Conduct and Code of Ethics for Senior Financial Officers are available at http://www.marathon.com/Investor_Center/Corporate_Governance/.

Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q and Current Reports on Form 8-K, as well as any amendments and exhibits to those reports, are available free of charge through our website as soon as reasonably practicable after the reports are filed or furnished with the SEC. These documents are also available in hard copy, free of charge, by contacting our Investor Relations office. Information contained on our website is not incorporated into this Annual Report on Form 10-K or other securities filings.

Item 1A. Risk Factors

We are subject to various risks and uncertainties in the course of our business. The following summarizes significant risks and uncertainties that may adversely affect our business, financial condition or results of operations.

A substantial or extended decline in liquid hydrocarbon or natural gas prices, or in refining and wholesale marketing gross margins, would reduce our operating results and cash flows and could adversely impact our future rate of growth and the carrying value of our assets.

Prices for liquid hydrocarbons and natural gas and refining and wholesale marketing gross margins fluctuate widely. Our revenues, operating results and future rate of growth are highly dependent on the prices we receive for our liquid hydrocarbons and natural gas and the margins we realize on our refined products. Historically, the markets for liquid hydrocarbons, natural gas and refined products have been volatile and may continue to be volatile in the future. Many of the factors influencing prices of liquid hydrocarbons and natural gas and refining and wholesale marketing gross margins are beyond our control. These factors include:

- worldwide and domestic supplies of and demand for liquid hydrocarbons, natural gas and refined products;
- the cost of exploring for, developing and producing liquid hydrocarbons and natural gas;
- the cost of crude oil to be manufactured into refined products;
- utilization rates of refineries;
- natural gas and electricity supply costs incurred by refineries;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain production controls;
- political instability or armed conflict in oil and natural gas producing regions;
- changes in weather patterns and climate;
- natural disasters such as hurricanes and tornados;
- the price and availability of alternative and competing forms of energy;
- domestic and foreign governmental regulations and taxes; and
- general economic conditions worldwide.

The long-term effects of these and other factors on the prices of liquid hydrocarbons and natural gas, as well as on refining and wholesale marketing gross margins, are uncertain.

Lower liquid hydrocarbon and natural gas prices, may cause us to reduce the amount of these commodities that we produce, which may reduce our revenues, operating income and cash flows. Significant reductions in liquid hydrocarbon and natural gas prices or refining and wholesale marketing gross margins could require us to reduce our capital expenditures or impair the carrying value of our assets.

Estimates of liquid hydrocarbon, natural gas and synthetic crude oil reserves depend on many factors and assumptions, including various assumptions that are based on conditions in existence as of the dates of the estimates. Any material changes in those conditions or other factors affecting those assumptions could impair the quantity and value of our liquid hydrocarbon, natural gas and synthetic crude oil reserves.

The proved reserve information included in this report has been derived from engineering estimates. Estimates of liquid hydrocarbon and natural gas reserves were prepared by our in-house teams of reservoir engineers and geoscience professionals and were reviewed, on a selected basis, by our Corporate Reserves Group or third-party consultants. The synthetic crude oil reserves estimates were prepared by GLJ Petroleum Consultants, a third-party consulting firm experienced in working with oil sands. Reserves were priced at the average of closing prices for the first day of each month in the 12-month period ended December 31, 2009, as well as other conditions in existence at the date. Any significant future price changes will have a material effect on the quantity and present value of our proved reserves. Future reserve revisions could also result from changes in governmental regulation, among other things.

Reserve estimation is a subjective process that involves estimating volumes to be recovered from underground accumulations of liquid hydrocarbon, natural gas and bitumen that cannot be directly measured. (Bitumen is mined then upgraded into synthetic crude oil.) Estimates of economically producible reserves and of future net cash flows depend upon a number of variable factors and assumptions, including:

- location, size and shape of the accumulation as well as fluid, rock and producing characteristics of the accumulation;
- historical production from the area, compared with production from other comparable producing areas;
- volumes of bitumen in-place and various factors affecting the recoverability of bitumen and its conversion into synthetic crude oil such as historical upgrader performance;
- the assumed effects of regulation by governmental agencies;
- assumptions concerning future operating costs, severance and excise taxes, development costs and workover and repair costs, and
- industry economic conditions, levels of cash flows from operations and other operating considerations.

As a result, different petroleum engineers, each using industry-accepted geologic and engineering practices and scientific methods, may produce different estimates of proved reserves and future net cash flows based on the same available data. Because of the subjective nature of such reserve estimates, each of the following items may differ materially from the amounts or other factors estimated:

- the amount and timing of production;
- the revenues and costs associated with that production; and
- the amount and timing of future development expenditures.

The discounted future net revenues from our proved liquid hydrocarbon, natural gas and synthetic crude oil reserves reflected in this report should not be considered as the market value of the reserves attributable to our properties. As required by SEC Rule 4-10 of Regulation S-X, the estimated discounted future net revenues from our proved liquid hydrocarbon, natural gas and synthetic crude oil reserves are based on an average of closing prices for the first day of each month in the 12-month period ended December 31, 2009, and costs applicable at the date of the estimate, while actual future prices and costs may be materially higher or lower.

In addition, the 10 percent discount factor required by the applicable rules of the SEC to be used to calculate discounted future net revenues for reporting purposes is not necessarily the most appropriate discount factor based on our cost of capital and the risks associated with our business and the oil and natural gas industry in general.

If we are unsuccessful in acquiring or finding additional reserves, our future liquid hydrocarbon and natural gas production would decline, thereby reducing our cash flows and results of operations and impairing our financial condition.

The rate of production from liquid hydrocarbon and natural gas properties generally declines as reserves are depleted. Except to the extent we acquire interests in additional properties containing proved reserves, conduct successful exploration and development activities or, through engineering studies, optimize production performance, identify additional reservoirs not currently producing or secondary recovery reserves, our proved reserves will decline materially as liquid hydrocarbons and natural gas are produced. Accordingly, to the extent we are not successful in replacing the liquid hydrocarbons and natural gas we produce, our future revenues will decline. Creating and maintaining an inventory of prospects for future production depends on many factors, including:

- obtaining rights to explore for, develop and produce liquid hydrocarbons and natural gas in promising areas;
- drilling success;
- the ability to complete long lead-time, capital-intensive projects timely and on budget;
- the ability to find or acquire additional proved reserves at acceptable costs; and
- the ability to fund such activity.

The availability of crude oil and increases in crude oil prices may reduce our refining, marketing and transportation profitability and refining and wholesale marketing gross margins.

The profitability of our refining, marketing and transportation operations depends largely on the margin between the cost of crude oil and other feedstocks that we refine and the selling prices we obtain for refined products. We are a net purchaser of crude oil. A significant portion of our crude oil is purchased from various foreign national oil companies, producing companies and trading companies, including suppliers from the Middle East. These purchases are subject to political, geographic and economic risks and possible terrorist activities attendant to doing business with suppliers located in that area of the world. Our overall refining, marketing and transportation profitability could be adversely affected by the availability of supply and rising crude oil and other feedstock prices which we do not recover in the marketplace. Refining and wholesale marketing gross margins historically have been volatile and vary with the level of economic activity in the various marketing areas, the regulatory climate, logistical capabilities and the available supply of refined products.

We will continue to incur substantial capital expenditures and operating costs as a result of compliance with, and changes in environmental health, safety and security laws and regulations, and, as a result, our profitability could be materially reduced.

Our businesses are subject to numerous laws, regulations and other requirements relating to the protection of the environment, including those relating to the discharge of materials into the environment, waste management, pollution prevention, greenhouse gas emissions, and characteristics and composition of gasoline and diesel fuels, as well as laws and regulations relating to public and employee safety and health and to facility security. We have incurred and will continue to incur substantial capital, operating and maintenance, and remediation expenditures as a result of these laws and regulations. To the extent these expenditures, as with all costs, are not ultimately reflected in the prices of our products and services, our operating results will be adversely affected. The specific impact of these laws and regulations on us and our competitors may vary depending on a number of factors, including the age and location of operating facilities, marketing areas, crude oil and feedstock sources, and production processes. We may also be required to make material expenditures to modify operations, install pollution control equipment, perform site cleanups or curtail operations. We may become subject to liabilities that we currently do not anticipate in connection with new, amended or more stringent requirements, stricter interpretations of existing requirements or the future discovery of contamination. In addition, any failure by us to comply with existing or future laws or regulations could result in civil penalties or criminal fines and other enforcement actions against us.

We believe it is likely that the scientific and political attention to issues concerning the extent, causes of and responsibility for climate change will continue, with the potential for further regulations that could affect our operations. Currently, various legislative and regulatory measures to address greenhouse gas emissions (including carbon dioxide, methane and nitrous oxides) are in various phases of review, discussion or implementation in the United States, Canada and European Union. These include proposed federal legislation and state actions to develop statewide or regional programs, each of which could impose reductions in greenhouse gas emissions. These actions could result in increased costs to (1) costs to operate and maintain our facilities, (2) capital expenditures to install new emission controls at our refineries and other facilities, and (3) costs to administer and manage any potential greenhouse gas emissions or carbon trading or tax programs. These costs and capital expenditures could be material. Although uncertain, these developments could increase our costs, reduce the demand for the products we sell and create delays in our obtaining air pollution permits for new or modified facilities.

State, national and international legislation to reduce greenhouse gas emissions are being proposed and, in some cases, promulgated. This legislation applies or could apply in countries in which we operate. Our liquid hydrocarbon, natural gas and synthetic crude oil production and processing operations typically result in emissions of greenhouse gases. Likewise, emissions arise from our RM&T operations, including the refining of crude oil, and from the use of our refined petroleum products by our customers. Legislation or regulatory activity that impacts or could impact our operations includes:

- EPA issued a finding that greenhouse gases contribute to air pollution that endangers public health and welfare. Related to the endangerment finding, in September of 2009, the EPA proposed a greenhouse gas emission standard for mobile sources (cars and other light duty vehicles). This standard is expected to be finalized in the spring of 2010. The endangerment finding along with the mobile source standard are expected to lead to widespread regulation of stationary sources of greenhouse gas emissions, and in October of 2009 the EPA proposed a so-called tailoring rule to limit the applicability of the EPA's major permitting programs to larger sources of greenhouse gas emissions, such as our refineries and a few large production facilities.
- In the U.S., the House of Representatives and the Senate each have their own form of cap and trade legislation to reduce carbon emissions (Waxman-Markey Bill and the Kerry-Boxer Bill). Among other actions, cap and trade systems require businesses that emit greenhouse gases to buy emission credits from the government, other businesses, or through an auction process.
- Although not ratified in the United States, the Kyoto Protocol, effective in 2005, has been ratified by countries in which we have or in the future may have operations.
- The Copenhagen Accord was reached in December 2009 with the United States pledging to reduce emissions 17 percent below 2005 levels by 2020.
- The Canadian federal government has not enacted greenhouse gas emission reduction legislation although it has announced a commitment to reduce the country's emissions 17 percent from 2005 levels by 2020, to be pursued through a cap and trade system.
- The European Union ("EU") Emissions Trading Scheme is in its second phase which runs from 2008 to 2012, in which EU member governments provide a certain number of free allowances to facilities and a facility may purchase additional EU allowances from other facilities, traders and the government. Through 2009, we have complied with this program by using the allocated free allowances or by borrowing on our future year allowances.
- The Canadian federal government and province of Alberta jointly announced their intent to partially fund the AOSP's Quest Carbon Capture and Storage ("Quest CCS") project. Under the terms of their letters of intent, Alberta would contribute 745 million Canadian dollars and the Government of Canada would provide 120 million Canadian dollars toward the project's development. The Quest project would store approximately 1.1 million tons of carbon dioxide annually and should allow the AOSP to meet Canadian and Alberta emission reduction requirements for the foreseeable future. A final investment decision on the Quest CCS project will be made at a later date, and is subject to regulatory approvals, stakeholder engagement, detailed engineering studies, as well as the agreement of joint venture partners.
- The State of California enacted legislation effective in 2007 capping California's greenhouse gas emissions at 1990 levels by 2020 and directed its responsible state agency to adopt mandatory reporting rules for significant sources of greenhouse gases. We have not conducted significant business in California in recent years, but other states where we have operations could adopt similar greenhouse gas legislation.

Although there may be adverse financial impact (including compliance costs, potential permitting delays and potential reduced demand for crude oil or certain refined products) associated with any legislation, regulation, the EPA or other action, the extent and magnitude of that impact cannot be reliably or accurately estimated due to the fact that requirements have only recently been adopted and the present uncertainty regarding the additional measures and how they will be implemented. Private party litigation has also been brought against emitters of greenhouse gas emissions, but we have not been named in those cases.

Our operations and those of our predecessors could expose us to civil claims by third parties for alleged liability resulting from contamination of the environment or personal injuries caused by releases of hazardous substances. For example, we have been, and presently are, a defendant in various litigation and other proceedings involving products liability and other claims related to alleged contamination of groundwater with the oxygenate methyl tertiary-butyl ether ("MTBE'). We may become involved in further litigation or other proceedings, or we may be held responsible in existing or future litigation or proceedings, the costs of which could be material.

We have in the past operated retail marketing sites with underground storage tanks ("USTs") in various jurisdictions and are currently operating retail marketing sites that have USTs in numerous states. Federal and state regulations and legislation govern the USTs, and compliance with those requirements can be costly. The operation of USTs also poses certain other risks, including damages associated with soil and groundwater contamination. Leaks from USTs which may occur at one or more of our retail marketing sites, or which may have occurred at our previously operated retail marketing sites, may impact soil or groundwater and could result in fines or civil liability for us.

Environmental laws are subject to frequent change and many of them have become more stringent. In some cases, they can impose liability for the entire cost of cleanup on any responsible party, without regard to negligence or fault, and impose liability on us for the conduct of others or conditions others have caused, or for our acts that complied with all applicable requirements when we performed them.

If we are unable to complete capital projects at their expected costs and in a timely manner, or if the market conditions assumed in our project economics deteriorate, our business, financial condition, results of operations and cash flows could be materially and adversely affected.

Delays or cost increases related to capital spending programs involving engineering, procurement and construction of facilities (including improvements and repairs to our existing facilities) could adversely affect our ability to achieve forecasted internal rates of return and operating results. Delays in making required changes or upgrades to our facilities could subject us to fines or penalties as well as affect our ability to supply certain products we produce. Such delays or cost increases may arise as a result of unpredictable factors, many of which are beyond our control, including:

- denial of or delay in receiving requisite regulatory approvals and /or permits;
- unplanned increases in the cost of construction materials or labor;
- disruptions in transportation of components or construction materials;
- adverse weather conditions, natural disasters or other events (such as equipment malfunctions, explosions, fires or spills) affecting our facilities, or those of vendors or suppliers;
- shortages of sufficiently skilled labor, or labor disagreements resulting in unplanned work stoppages;
- market-related increases in a project's debt or equity financing costs; and
- nonperformance by, or disputes with, vendors, suppliers, contractors or subcontractors.

Any one or more of these factors could have a significant impact on our ongoing capital projects. If we were unable to make up the delays associated with such factors or to recover the related costs, or if market conditions change, it could materially and adversely affect our business, financial conditions, results of operations and cash flows.

Many of our major projects and operations are conducted with partners, which may decrease our ability to manage risk.

We often enter into arrangements to conduct certain business operations, such oil and gas exploration and production, oil sands mining or pipeline transportation, with partners in order to share risks associated with those operations. However, these arrangements also may decrease our ability to manage risks and costs, particularly where we are not the operator. We could have limited influence over and control of the behaviors and performance of these operations. This could affect our operational performance, financial position and reputation.

Uncertainty in the financial markets may impact our ability to obtain future financing and could adversely affect entities with which we do business.

In the future we may require financing to grow our business. Financial institutions participate in our revolving credit facility and provide us with services including insurance, cash management, commercial letters of credit, derivative instruments, and short-term investments. Uncertainty affecting the financial markets and the possibility that financial institutions may consolidate or go bankrupt has altered levels of activity in the financial markets. A deterioration of the financial market conditions could significantly increase our costs associated with borrowing. Our liquidity and our ability to access the credit and/or capital markets may also be adversely affected by changes in the financial markets and the global economy. In addition, there could be a number of follow-on effects from continued turmoil on us, including insolvency of customers, key suppliers, partners, and other counterparties.

Worldwide political and economic developments could damage our operations and materially reduce our profitability and cash flows.

Local political and economic factors in global markets could have a material adverse effect on us. A total of 29 percent of our liquid hydrocarbon and natural gas sales volumes in 2009 was derived from production outside the United States and 71 percent of our proved liquid hydrocarbon and natural gas reserves as of December 31, 2009, were located outside the United States. All of our synthetic crude oil production and proved reserves are located in Canada. In addition, a significant portion of the feedstock requirements for our refineries is satisfied through supplies originating in Saudi Arabia, Kuwait, Canada, Mexico and various other foreign countries. We are, therefore, subject to the political, geographic and economic risks and possible terrorist activities attendant to doing business with suppliers located in, and supplies originating from, those areas. There are many risks associated with operations in global markets, including changes in governmental policies relating to liquid hydrocarbon, natural gas, bitumen, synthetic crude oil or refined product pricing and taxation, other political, economic or diplomatic developments and international monetary fluctuations. These risks include:

- political and economic instability, war, acts of terrorism and civil disturbances;
- the possibility that a government may seize our property with or without compensation, may attempt to renegotiate or revoke existing contractual arrangements or may impose additional taxes or royalty burdens; and
- fluctuating currency values, hard currency shortages and currency controls.

Continued hostilities in the Middle East and the occurrence or threat of future terrorist attacks could adversely affect the economies of the United States and other developed countries. A lower level of economic activity could result in a decline in energy consumption, which could cause our revenues and margins to decline and limit our future growth prospects. These risks could lead to increased volatility in prices for liquid hydrocarbons, natural gas and refined products. In addition, these risks could increase instability in the financial and insurance markets and make it more difficult for us to access capital and to obtain the insurance coverage that we consider adequate.

Actions of governments through tax and other legislation, executive order and commercial restrictions could reduce our operating profitability, both in the United States and abroad. The U.S. government can prevent or restrict us from doing business in foreign countries. These restrictions and those of foreign governments have in the past limited our ability to operate in, or gain access to, opportunities in various countries and will continue to do so in the future.

Our operations are subject to business interruptions and casualty losses. We do not insure against all potential losses and therefore we could be seriously harmed by unexpected liabilities and increased costs.

Our exploration and production operations are subject to unplanned occurrences, including blowouts, explosions, fires, loss of well control, spills, hurricanes and other adverse weather, labor disputes and accidents. Our oil sands mining operations are subject to business interruptions due to breakdown or failure of equipment or processes and unplanned events such as fires, earthquakes, explosions or other interruptions. In addition, our refining, marketing and transportation operations are subject to business interruptions due to scheduled refinery turnarounds and unplanned events such as explosions, fires, pipeline ruptures or other interruptions, crude oil or refined product spills, severe weather and labor disputes. These same risks can be applied to the third-parties which transport crude oil and refined products to, from and among facilities. A prolonged disruption in the ability of any pipeline or vessels to transport crude oil or refined products could contribute to a business interruption or increase costs.

Our operations are also subject to the additional hazards of pollution, releases of toxic gas and other environmental hazards and risks, as well as hazards of marine operations, such as capsizing, collision, acts of piracy and damage or loss from severe weather conditions. These hazards could result in serious personal injury or loss of human life, significant damage to property and equipment, environmental pollution, impairment of operations and substantial losses to us. Various hazards have adversely affected us in the past, and damages resulting from a catastrophic occurrence in the future involving us or any of our assets or operations may result in our being named as a defendant in one or more lawsuits asserting potentially large claims or in our being assessed potentially substantial fines by governmental authorities. We maintain insurance against many, but not all, potential losses or liabilities arising from operating hazards in amounts that we believe to be prudent. Uninsured losses and liabilities arising from operating hazards could reduce the funds available to us for capital, exploration and investment spending and could have a material adverse effect on our business, financial condition, results of operations and cash flows. Historically, we have maintained insurance coverage for physical damage and resulting business interruption to our major onshore and offshore facilities, with significant self-insured retentions. In the future, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies have increased substantially and could escalate further. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. For example, due to hurricane activity in recent years, the availability of insurance coverage for our offshore facilities for windstorms in the Gulf of Mexico region has been reduced or, in many instances, it is prohibitively expensive. As a result, our exposure to losses from future windstorm activity in the Gulf of Mexico region has increased.

If the transactions resulting in our acquisition of the minority interest in MPC previously owned by Ashland were found to constitute a fraudulent transfer or conveyance, we could be required to provide additional consideration to Ashland or to return a portion of the interest in MPC, and either of those results could have a material adverse effect on us.

In a bankruptcy case or lawsuit initiated by one or more creditors or a representative of creditors of Ashland, a court could review our 2005 transactions with Ashland under state fraudulent transfer or conveyance laws. Under those laws, the transactions would be deemed fraudulent if the court determined that the transactions were undertaken for the purpose of hindering, delaying or defrauding creditors or that the transactions were constructively fraudulent. If the transactions were found to be a fraudulent transfer or conveyance, we might be required to provide additional consideration to Ashland or to return all or a portion of the interest in MPC and the other assets we acquired from Ashland as a result of those transactions.

In connection with our transactions with Ashland completed in 2005, we delivered part of the overall consideration (specifically, shares of Marathon common stock having a value of $915 million) to Ashland's shareholders. We obtained opinions from a nationally recognized appraisal firm that Ashland received reasonably equivalent value or fair consideration from us in the transactions and that Ashland was not insolvent either before or after giving effect to the closing of the transactions. Although we are confident in our conclusions regarding Ashland's receipt of reasonably equivalent value or fair consideration and its solvency both before and after giving effect to the closing of our transactions, such determinations involve numerous assumptions and uncertainties, and it is possible that a court could disagree with our conclusions.

Litigation by private plaintiffs or government officials could adversely affect our performance.

We currently are defending litigation and anticipate that we will be required to defend new litigation in the future. The subject matter of such litigation may include releases of hazardous substances from our facilities, products liability, consumer credit or privacy laws, product pricing or antitrust laws or any other laws or regulations that apply to our operations. While an adverse outcome in most litigation matters would not be expected to be material to us, in some cases the plaintiff or plaintiffs seek alleged damages involving large classes of potential litigants, and may allege damages relating to extended periods of time or other alleged facts and circumstances. If we are not able to successfully defend such claims, they may result in substantial liability. We do not have insurance covering all of these potential liabilities. There has been a trend in recent years of litigation by attorneys general and other government officials seeking to recover civil damages from companies. We are defending litigation of that type and anticipate that we will be required to defend new litigation of that type in the future. In addition to substantial liability, litigation may also seek injunctive relief which could have an adverse effect on our future operations.

We may issue preferred stock whose terms could dilute the voting power or reduce the value of Marathon common stock.

Our restated certificate of incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such preferences, powers and relative, participating, optional and other rights, including preferences over Marathon common stock respecting dividends and distributions, as our Board of Directors generally may determine. The terms of one or more classes or series of preferred stock could dilute the voting power or reduce the value of Marathon common stock. For example, we could grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we could assign to holders of preferred stock could affect the residual value of the common stock.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

The location and general character of our principal liquid hydrocarbon and natural gas properties, oil sands mining properties and facilities, refineries, pipeline systems and other important physical properties have been described by segment under Item 1. Business. Except for oil and gas producing properties, including oil sands mines, which generally are leased, or as otherwise stated, such properties are held in fee. The plants and facilities have been constructed or acquired over a period of years and vary in age and operating efficiency. At the date of acquisition of important properties, titles were examined and opinions of counsel obtained, but no title examination has been made specifically for the purpose of this document. The properties classified as owned in fee generally have been held for many years without any material unfavorably adjudicated claim.

Net liquid hydrocarbon, natural gas, and synthetic crude oil sales volumes, with net bitumen production volumes are set forth in Item 8. Financial Statements and Supplementary Data – Supplemental Statistics. Estimated net proved liquid hydrocarbon, natural gas and synthetic crude oil reserves are set forth in Item 8. Financial Statements and Supplementary Data – Supplementary Information on Oil and Gas Producing Activities – Estimated Quantities of Proved Oil and Gas Reserves. The basis for estimating these reserves is discussed in Item 1. Business – Reserves.

Item 3. Legal Proceedings

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

MTBE Litigation

We, along with other refining companies, 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 27 cases arising in four states alleging damages for MTBE contamination. Like the cases that we settled in 2008, 12 of the remaining cases are consolidated in a multi-district litigation ("MDL") in the Southern District of New York for pretrial proceedings. The other 15 cases are in New York state courts (Nassau and Suffolk Counties). Plaintiffs in 26 of the 27 cases allege damages to water supply wells from contamination of groundwater by MTBE, similar to the damages claimed in the cases settled in 2008. In the remaining case, the New Jersey Department of Environmental Protection is seeking the cost of remediating MTBE contamination and natural resources damages allegedly resulting from contamination of groundwater by MTBE. We are vigorously defending these cases. We have engaged in settlement discussions related to the majority of these cases. We do not expect our share of liability for these cases to significantly impact our consolidated results of operations, financial position or cash flows. We voluntarily discontinued producing MTBE in 2002.

Natural Gas Royalty Litigation

We are currently a party to one qui tam case, which alleges that Marathon and other defendants violated the False Claims Act with respect to the reporting and payment of royalties on natural gas and natural gas liquids for federal and Indian leases. A qui tam action is an action in which the relator files suit on behalf of himself as well as the federal government. The case currently pending is U.S. ex rel Harrold E. Wright v. Agip Petroleum Co. et al. It is primarily a gas valuation case. Marathon has reached a settlement with the Relator and the DOJ which will be finalized after the Indian Tribes review and approve the settlement terms. Such settlement is not expected to significantly impact our consolidated results of operations, financial position or cash flows.

Product Contamination Litigation

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 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.

Environmental Proceedings

U.S. EPA Litigation

In 2006, we and other oil and gas companies joined the State of Wyoming in filing a petition for review against the U.S. EPA in the U.S. District Court for the District of Wyoming. These actions seek a court order mandating the U.S. EPA to disapprove Montana's 2006 amended water quality standards, on grounds that the standards lack sound scientific justification, they are arbitrary and capricious, and were adopted contrary to law. The water quality amendments at issue could require more stringent discharge limits and have the potential to require certain Wyoming coal bed methane operations to perform more costly water treatment or inject produced water. Approval of these standards could delay or prevent obtaining permits needed to discharge produced water to streams flowing from Wyoming into Montana. In February 2008, U.S. EPA approved Montana's 2006 regulations, and we amended our petition for review. The court stayed this case while the U.S. EPA mediated the matter between Montana, Wyoming and the Northern Cheyenne tribe. The mediation was unsuccessful; however the Court ultimately vacated the U.S. EPA's approval of the 2003 and 2006 Montana standards and remanded the matter to the U.S. EPA with instructions for reconsideration. The federal government filed a Notice of Appeal, but subsequently filed a voluntary Motion to dismiss which was granted by the District Court. In sum, the U.S. EPA must now decide whether to approve or disapprove Montana's 2006 water quality standards consistent with the Court's remand instructions.

Montana Litigation

In June 2006, we filed a complaint for declaratory judgment in Montana State District Court against the Montana Board of Environmental Review ("MBER") and the Montana Department of Environmental Quality, seeking to set aside and declare invalid certain regulations of the MBER that single out the coal bed natural gas industry and a few streams in eastern Montana for excessively severe and unjustified restrictions for surface water discharges of produced water from coal bed methane operations. None of the streams affected by the regulations suffers impairment from coal bed natural gas discharges. The court, in deferring to the MBER's discretion, upheld the MBER's regulations. This decision was affirmed by the Montana Supreme Court; this decision in the meanwhile does not impact our operations due to a decision in the litigation with U.S. EPA in Wyoming Federal District Court, reversing U.S. EPA's approval of the Montana regulations.

Colorado Litigation

In 2008, the State of Colorado, through its Department of Public Health and Environment, filed a state court suit against us and others alleging violations of storm water requirements in and around an upstream production facility. The matter was resolved in the third quarter of 2009 with the parties paying a penalty of $280,000 of which our share was $98,000.

New Mexico Litigation

In December 2008, the State of New Mexico filed a state court suit against us alleging violations of the New Mexico Air Quality Control Act. The lawsuit arose out of a February 2008 notice of violation issued to our Indian

Basin Natural Gas Plant. We believe there has been no adverse impact to public health or the environment, having implemented voluntary emission reduction measures over the years. We have finalized a consent order and the court has approved it. The order requires a cash penalty of $610,560 plus plant compliance projects and supplemental environmental projects estimated to cost over $5 million. We were the operator and part owner of the plant through June 2009. We are working with the other plant owners to obtain reimbursement for their share of these costs.

Powder River Basin Litigation

The U.S. Bureau of Land Management ("BLM") completed multi-year reviews of potential environmental impacts from coal bed methane development on federal lands in the Powder River Basin, including those in Wyoming. The BLM signed a Record of Decision ("ROD") on April 30, 2003, supporting increased coal bed methane development. Plaintiff environmental and other groups filed suit in May 2003 in federal court against the BLM to stop coal bed methane development on federal lands in the Powder River Basin until the BLM conducted additional environmental impact studies. Marathon intervened as a party in the ongoing litigation before the Wyoming Federal District Court. As these lawsuits to delay energy development in the Powder River Basin progressed through the courts, the Wyoming BLM continued to process permits to drill under the ROD. During the last quarter of 2008, the Court ruled in BLM's favor, finding its environmental studies and stewardship were adequate and protective under federal law. The plaintiffs have appealed this ruling to the 10th Circuit Court of Appeals and are currently awaiting oral arguments.

Other Environmental Proceedings

The following is a summary of proceedings involving us that were pending or contemplated as of December 31, 2009, under federal and state environmental laws. Except as described herein, it is not possible to predict accurately the ultimate outcome of these matters; however, management's belief set forth in the first paragraph under Legal Proceedings above takes such matters into account.

Claims under CERCLA and related state acts have been raised with respect to the clean-up of various waste disposal and other sites. CERCLA is intended to facilitate the clean-up of hazardous substances without regard to fault. Potentially responsible parties ("PRPs") for each site include present and former owners and operators of, transporters to and generators of the substances at the site. Liability is strict and can be joint and several. Because of various factors including the difficulty of identifying the responsible parties for any particular site, the complexity of determining the relative liability among them, the uncertainty as to the most desirable remediation techniques and the amount of damages and clean-up costs and the time period during which such costs may be incurred, we are unable to reasonably estimate our ultimate cost of compliance with CERCLA.

The projections of spending for and/or timing of completion of specific projects provided in the following paragraphs are forward-looking statements. These forward-looking statements are based on certain assumptions including, but not limited to, the factors provided in the preceding paragraph. To the extent that these assumptions prove to be inaccurate, future spending for and/or timing of completion of environmental projects may differ materially from those stated in the forward-looking statements.

As of December 31, 2009, we had been identified as a PRP at a total of nine CERCLA waste sites. Based on currently available information, which is in many cases preliminary and incomplete, we believe that our liability for clean-up and remediation costs in connection with three of these sites will be under $100,000 and one site will be under $200,000. As to two sites, we believe that our liability for clean-up and remediation costs will be under $4 million per site. We are not far enough along in the process to determine the cost for the remaining three sites, but two of those sites may be $1 million to $2 million or more each and the other site may be under $1 million. In addition, there are four sites for which we have received information requests or other indications that we may be a PRP under CERCLA, but for which sufficient information is not presently available to confirm the existence of liability.

There are also 116 sites, excluding retail marketing outlets, where remediation is being sought under other environmental statutes, both federal and state, or where private parties are seeking remediation through discussions or litigation. Based on currently available information, which is in many cases preliminary and incomplete, we believe that liability for clean-up and remediation costs in connection with five of these sites will be under $100,000 per site, that 55 sites have potential costs between $100,000 and $1 million per site and that 29 sites may involve remediation costs between $1 million and $5 million per site. Ten sites have incurred remediation costs of more than $5 million per site. With respect to the remaining 17 sites, Ashland retains responsibility to us for remediation, subject to caps and other requirements contained in the agreements with Ashland related to the acquisition of Ashland's minority interest in Marathon Petroleum Company LLC in 2005. We estimate that we will be responsible for $18 million in remediation costs at these sites which will not be reimbursed by Ashland, and we have included this amount in our accrued environmental remediation liabilities.

There is one site that involves a remediation program in cooperation with the Michigan Department of Environmental Quality ("MDEQ") at a closed and dismantled refinery site located near Muskegon, Michigan. During the next 27 years, we anticipate spending approximately $4.6 million in remediation costs at this site. In 2010, interim remediation measures will continue to occur and appropriate site characterization and risk-based assessments necessary for closure will be refined and may change the estimated future expenditures for this site. The closure strategy being developed for this site and ongoing work at the site are subject to approval by the MDEQ. Expenditures for remedial measures in 2009 and 2008 were $291,000 and $434,000, respectively, with expenditures for remedial measures in 2010 expected to be approximately $1.6 million.

We are subject to a pending enforcement matter with the Illinois Environmental Protection Agency and the Illinois Attorney General's Office since 2002 concerning self-reporting of possible emission exceedences and permitting issues related to storage tanks at the Robinson, Illinois, refinery. There were no developments in this matter in 2009.

During 2001, we entered into a New Source Review consent decree and settlement of alleged Clean Air Act ("CAA") and other violations with the U.S. EPA covering all of our refineries. The settlement committed us to specific control technologies and implementation schedules for environmental expenditures and improvements to our refineries over approximately an eight-year period, which are now substantially complete. In addition, we have been working on certain agreed-upon supplemental environmental projects as part of this settlement of an enforcement action for alleged CAA violations and these have been completed. As part of this consent decree, we were required to conduct evaluations of refinery benzene waste air pollution programs (benzene waste "NESHAPS"). Subject to entering a formal consent decree or further amendment of the New Source Review consent decree to memorialize our understanding, we have agreed with the U.S. Department of Justice and U.S. EPA to pay a civil penalty of $408,000 and conduct supplemental environmental projects of approximately $1 million, as part of a settlement of an enforcement action for alleged CAA violations relating to benzene waste NESHAPS. We anticipate entering into a formal consent decree or amendment to resolve these matters in 2010.

In May 2008, the Texas Commission on Environmental Quality ("TCEQ") performed a benzene waste NESHAPS inspection at the Texas City Refinery. The TCEQ subsequently issued a notice of enforcement and a proposed penalty agreed order. This matter was concluded whereby all parties agreed to a Supplemental Environmental Project (SEP) requiring Marathon to operate an on-site ambient air monitoring system for twelve months.

The U.S. Occupational Safety and Health Administration ("OSHA") previously announced a National Emphasis Program to inspect most domestic oil refineries. The inspections began in 2007 and focused on compliance with the OSHA Process Safety Management requirements. OSHA or state-equivalent agencies have conducted inspections at the Canton, Robinson, Catlettsburg, Detroit, Texas City, and St. Paul Park refineries with agreed–to penalties of $321,500 and $135,000 imposed in Canton and Texas City, respectively. No penalties were imposed as a result of the other inspections. Inspections may occur at Garyville in 2010 and further enforcement action by OSHA or equivalent state agency may result.

In November 2008, the U.S. EPA issued a notice of violation for oil spills occurring at the Catlettsburg Refinery in 2004 and 2008. Marathon entered into two separate Consent Agreement/Final Orders (CAFOs) in 2009 resulting in civil penalties totaling $118,000.

Item 4. Submission of Matters to a Vote of Security Holders

None.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

The principal market on which Marathon common stock is traded is the New York Stock Exchange. Marathon common stock is also traded on the Chicago Stock Exchange. As of January 29, 2010, there were 55,325 registered holders of Marathon common stock. The frequency and amount of dividends paid during the last two years is set forth in Item 8. Financial Statements and Supplementary Data – Selected Quarterly Financial Data.

The following is the quarterly high and low sales prices for Marathon common stock:

	2009		2008	
	High	Low	High	Low
Quarter 1	$29.87	$20.92	$61.88	$45.23
Quarter 2	33.41	27.08	55.05	44.92
Quarter 3	33.88	28.03	52.78	37.48
Quarter 4	35.27	30.48	38.81	19.58

Dividends

Our Board of Directors intends to declare and pay dividends on Marathon common stock based on the financial condition and results of operations of Marathon Oil Corporation, although it has no obligation under Delaware law or the Restated Certificate of Incorporation to do so. In determining the dividend policy with respect to Marathon common stock, the Board will rely on our consolidated financial statements of Marathon. Dividends on Marathon common stock are limited to our legally available funds.

Issuer Purchases of Equity Securities

The following table provides information about purchases by Marathon and its affiliated purchaser during the quarter ended December 31, 2009, of equity securities that are registered by Marathon pursuant to Section 12 of the Securities Exchange Act of 1934:

	Column (a)	Column (b)	Column (c)	Column (d)
Period	Total Number of Shares Purchased (a)(b)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (d)	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (d)
10/01/09 – 10/31/09	1,408	$31.45	-	$2,080,366,711
11/01/09 – 11/30/09	29,476	$32.04	-	$2,080,366,711
12/01/09 – 12/31/09	48,807 (c)	$31.17	-	$2,080,366,711
Total	79,691	$31.50	-	

(a) 31,849 shares of restricted stock were delivered by employees to Marathon, upon vesting, to satisfy tax withholding requirements.

(b) Under the terms of the transaction whereby we acquired the minority interest in Marathon Petroleum Company and other businesses from Ashland Inc. ("Ashland"), Ashland shareholders have the right to receive 0.2364 shares of Marathon common stock for each share of Ashland common stock owned on June 30, 2005 and cash in lieu of issuing fractional shares based on a value of $52.17 per share. In the fourth quarter of 2009, we acquired 7 shares due to acquisition share exchanges and Ashland share transfers pending at the closing of the transaction.

(c) 47,835 shares were repurchased in open-market transactions to satisfy the requirements for dividend reinvestment under the Marathon Oil Corporation Dividend Reinvestment and Direct Stock Purchase Plan (the "Dividend Reinvestment Plan") by the administrator of the Dividend Reinvestment Plan. Shares needed to meet the requirements of the Dividend Reinvestment Plan are either purchased in the open market or issued directly by Marathon.

(d) We announced a share repurchase program in January 2006, and amended it several times in 2007 for a total authorized program of $5 billion. As of December 31, 2009, 66 million split adjusted common shares had been acquired at a cost of $2,922 million, which includes transaction fees and commissions that are not reported in the table above. No shares have been repurchased under this program since August 2008.

Item 6. Selected Financial Data

(Dollars in millions, except as noted)	2009 [a]	2008 [a][b]	2007 [a][c][d]	2006 [a][e]	2005 [a][f]
Statement of Income Data					
Revenues	$ 53,470	$ 76,754	$ 64,096	$ 64,439	$ 62,594
Income from continuing operations	1,184	3,384	3,766	4,787	2,853
Net income	1,463	3,528	3,956	5,234	3,032
Per Share Data					
Basic :					
Income from continuing operations	$ 1.67	$ 4.77	$ 5.46	$ 6.69	$ 4.01
Net income	$ 2.06	$ 4.97	$ 5.73	$ 7.31	$ 4.26
Diluted :					
Income from continuing operations	$ 1.67	$ 4.75	$ 5.42	$ 6.63	$ 3.97
Net income	$ 2.06	$ 4.95	$ 5.69	$ 7.25	$ 4.22
Statement of Cash Flows Data					
Additions to property, plant and equipment	$ 6,231	$ 6,989	$ 3,757	$ 3,325	$ 2,643
Dividends paid	679	681	637	547	436
Dividends per share	$ 0.96	$ 0.96	$ 0.92	$ 0.76	$ 0.60
Balance Sheet Data as of December 31:					
Total assets	$ 47,052	$ 42,686	$ 42,746	$ 30,831	$ 28,498
Total long-term debt, including capitalized leases	8,436	7,087	6,084	3,061	3,698

(a) Our businesses in Ireland and Gabon were sold in 2009. All periods have been recast to reflect these businesses in discontinued operations.

(b) Includes a $1,412 million impairment of goodwill related to the OSM reporting unit, (see Note 15 to the consolidated financial statements) and a $25 million after-tax impairment ($40 million pretax) related to our investments in ethanol producing companies (see Note 13 to the consolidated financial statements).

(c) On October 18, 2007, we completed the acquisition of all the outstanding shares of Western. See Note 6 to the consolidated financial statements.

(d) Effective May 1, 2007, we no longer consolidate EGHoldings and our investment in EGHoldings is accounted for under the equity method of accounting; therefore, EGHoldings' capital expenditures subsequent to April 2007 are not included in our capital expenditures. See Note 4 to the consolidated financial statements.

(e) Effective April 1, 2006, we changed our accounting for matching buy/sell transactions. This change had no effect on income from continuing operations or net income, but the revenues and cost of revenues recognized after April 1, 2006, are less than the amounts that would have been recognized under previous accounting practices.

(f) On June 30, 2005, we acquired the 38 percent ownership interest in MPC previously held by Ashland, making it wholly-owned by Marathon.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

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

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

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

We hold a 60 percent interest in Equatorial Guinea LNG Holdings Limited ("EGHoldings"). As discussed in Note 4 to the consolidated financial statements, effective May 1, 2007, we ceased consolidating EGHoldings. Our investment is accounted for using the equity method of accounting. Unless specifically noted, amounts presented for the Integrated Gas segment for periods prior to May 1, 2007, include amounts related to the minority interests.

Management's Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the information under Item 1. Business, Item 1A. Risk Factors, Item 6. Selected Financial Data and Item 8. Financial Statements and Supplementary Data.

Overview

Exploration and Production

Prevailing prices for the various grades of crude oil and natural gas that we produce significantly impact our revenues and cash flows. Prices were volatile in 2009, but not as much as in the previous year. Prices in 2009 were also lower than in recent years as illustrated by the annual averages for key benchmark prices below.

Benchmark	2009	2008	2007
WTI crude oil (Dollars per barrel)	$62.09	$99.75	$72.41
Dated Brent crude oil (Dollars per barrel)	$61.67	$97.26	$72.39
Henry Hub natural gas (Dollars per mcf)[(a)]	$ 3.99	$ 9.04	$ 6.86

(a) First-of-month price index.

Crude oil prices rose sharply through the first half of 2008 as a result of strong global demand, a declining dollar, ongoing concerns about supplies of crude oil, and geopolitical risk. Later in 2008, crude oil prices sharply declined as the U.S. dollar rebounded and global demand decreased as a result of economic recession. The price decrease continued into 2009, but reversed after dropping below $33.98 in February, ending the year at $79.36.

Our domestic crude oil production is about 62 percent sour, which means that it contains more sulfur than light sweet WTI does. Sour crude oil also tends to be heavier than light sweet crude oil and sells at a discount to light sweet crude oil because of higher refining costs and lower refined product values. Our international crude oil production is relatively sweet and is generally sold in relation to the Dated Brent crude benchmark. The differential between WTI and Dated Brent average prices narrowed to $0.42 in 2009 compared to $2.49 in 2008 and $0.02 in 2007.

Natural gas prices on average were lower in 2009 than in 2008 and in 2007, with prices in 2008 hitting uniquely high levels. A significant portion of our natural gas production in the lower 48 states of the U.S. is sold at bid-week prices or first-of-month indices relative to our specific producing areas. A large portion of 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 also 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 be less than benchmark natural gas prices.

Oil Sands Mining

Oil Sands Mining 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 the normal output mix will track movements in WTI and one-third will track movements in the Canadian heavy sour crude oil marker, primarily Western Canadian Select. Output mix can be impacted by operational problems or planned unit outages at the mine or the 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 rates. 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 average benchmark prices that impact both our revenues and variable costs.

Benchmark	2009	2008	2007
WTI crude oil (Dollars per barrel)	$62.09	$99.75	$72.41
Western Canadian Select (Dollars per barrel)[a]	$52.13	$79.59	$49.60
AECO natural gas sales index (Dollars per mmbtu)[b]	$ 3.49	$ 7.74	$ 6.06

(a) Monthly pricing based upon average WTI adjusted for differentials unique to western Canada.
(b) Alberta Energy Company day ahead index.

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 west Africa, the U.S. and Europe.

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 2009, the gross sales from the plant were 3.9 million metric tonnes, while in 2008, its first full year of operations, the plant sold 3.4 million metric tonnes. Industry estimates of 2009 LNG trade are approximately 185 million metric tonnes. More LNG production facilities and tankers were under construction in 2009. As a result of the sharp worldwide economic downturn in 2008, continued weak economies are expected to lower natural gas consumption in various countries; therefore, affecting near-term demand for LNG. Long-term LNG supply continues to be in demand as markets seek the benefits of clean burning natural gas. Market prices for LNG are not reported or posted. 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 AMPCO. Gross sales of methanol from the plant totaled 960,374 metric tonnes in 2009 and 792,794 metric tonnes in 2008. 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. The 2010 Chemical Markets Associates, Inc. estimates world demand for methanol in 2009 was 41 million metric tonnes. Our plant capacity is 1.1 million, or about 3 percent of total demand.

Refining, Marketing and Transportation

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

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 market prices for refined products and crude oil, commonly used by the industry as a proxy for 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 producing 3 barrels of gasoline, 2 barrels of distillate and 1 barrel of residual fuel) are used for the crack spread calculation.

Our refineries can process significant amounts of sour crude oil which typically can be purchased at a discount to sweet crude oil. The amount of this discount, the sweet/sour differential, can vary significantly causing our refining and wholesale marketing gross margin to differ from the crack spreads which are based upon sweet crude. In general, a larger sweet/sour differential will enhance our refining and wholesale marketing gross margin. In 2009, the sweet/sour differential narrowed, due to a variety of worldwide economic and petroleum industry related factors, primarily related to lower hydrocarbon demand. Sour crude accounted for 50 percent, 52 percent and 54 percent of our crude oil processed in 2009, 2008 and 2007.

The following table lists calculated average crack spreads for the Midwest (Chicago) and Gulf Coast markets and the sweet/sour differential for the past three years.

(Dollars per barrel)	2009	2008	2007
Chicago LLS 6-3-2-1	$3.52	$ 3.27	$ 8.87
U.S. Gulf Coast LLS 6-3-2-1	$2.54	$ 2.45	$ 6.42
Sweet/Sour differential[(a)]	$5.82	$11.99	$11.59

(a) Calculated using the following mix of crude types as compared to LLS.: 15% Arab Light, 20% Kuwait, 10% Maya, 15% Western Canadian Select, 40% Mars.

In addition to the market changes indicated by the crack spreads and sweet/sour differential, 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.

Manufacturing costs are primarily driven by the cost of energy used by our refineries and the level of maintenance costs. Planned turnaround and major maintenance activities were completed at our Catlettsburg, Garyville, and Robinson refineries in 2009. We performed turnaround and major maintenance activities at our Robinson, Catlettsburg, Garyville and Canton refineries in 2008 and at our Catlettsburg, Robinson and St. Paul Park refineries in 2007.

Our retail marketing gross margin for gasoline and distillates, which is the difference between the ultimate price paid by consumers and the cost of refined products, including secondary transportation and consumer excise taxes, also impacts RM&T segment profitability. There are numerous factors including local competition, seasonal demand fluctuations, the available wholesale supply, the level of economic activity in our marketing areas and weather conditions that impact gasoline and distillate demand throughout the year. Refined product demand increased for several years until 2008 when it decreased due to the combination of significant increases in retail petroleum prices, a broad slowdown in general economic activity, and the impact of increased ethanol blending into gasoline. In 2009 refined product demand continued to decline. For our marketing area, we estimate a gasoline demand decline of about one percent and a distillate demand decline of about 12 percent from 2008 levels. Market demand declines for gasoline and distillates generally reduce the product margin we can realize. We also estimate gasoline and distillate demand in our marketing area decreased about three percent in 2008 compared to 2007 levels. The gross margin on merchandise sold at retail outlets has been historically less volatile.

2009 Highlights

E&P Segment

- Realized exceptional utilization of the Alvheim floating production, storage and offloading (FPSO) vessel, with a record average monthly production rate of 90,000 net boepd in October 2009.
- Achieved first oil from the Volund field in Norway ahead of schedule.
- Awarded 49 percent interest and will serve as operator in the Kumawa block offshore Indonesia.
- Announced the Marihone discovery south of the Volund and Alvheim fields offshore Norway.
- Progressed Droshky development in the Gulf of Mexico – currently on schedule and under budget.
- Announced Shenandoah deepwater discovery and leased 16 new blocks in the Gulf of Mexico.
- Announced Leda, Oberon and Tebe deepwater discoveries in Angola.
- Continued Bakken Shale production ramp-up, reaching a year-end rate over 11,000 net boepd.
- Added three onshore exploration licenses in Poland with shale gas potential (including one added in January 2010).

OSM Segment

- Added three additional leases in the AOSP area in Canada, which increased net proved reserves by 168 mmbbl.
- Progressed construction of the AOSP Phase 1 expansion, with mining operations anticipated in the second half of 2010, and the upgrader operations anticipated in late 2010 or early 2011.

Reserves

- Added net proved reserves of 674 mmboe, excluding dispositions, of which 603 mmbbl are proved synthetic crude reserves in Canada that were added under the new SEC regulations.

IG Segment

- Achieved operational availability of better than 95 percent at the Equatorial Guinea liquefied natural gas ("LNG") facility during 2009.

Refining, Marketing and Transportation Segment

- Completed Garyville Major Expansion project and began full integration with the base refinery.
- Progressed construction of Detroit Heavy Oil Upgrading Project, with completion expected in the second half of 2012.
- Increased Speedway SuperAmerica LLC same store gasoline sales volumes and merchandise sales 1.1 and 11.4 percent respectively, compared to 2008.

Divestitures

- Disposed of our exploration and production businesses in Ireland.
- Sold our operated fields offshore Gabon.
- Disposed of certain producing assets in the Permian Basin of New Mexico and Texas.
- Announced the sale of an undivided 20 percent outside-operated interest in the Production Sharing Contract and Joint Operating Agreement in Block 32 offshore Angola, which closed in February 2010.

Consolidated Results of Operations: 2009 compared to 2008

Revenues are summarized in the following table:

(In millions)	2009	2008
E&P	$ 7,851	$ 12,047
OSM	667	1,122
IG	50	93
RM&T	45,530	64,481
Segment revenues	54,098	77,743
Elimination of intersegment revenues	(700)	(1,207)
Gain on U.K. natural gas contracts	72	218
Total revenues	$ 53,470	$ 76,754
Items included in both revenues and costs:		
Consumer excise taxes on petroleum products and merchandise	$ 4,924	$ 5,065

E&P segment revenues decreased $4,196 million from 2008 to 2009, primarily due to lower average liquid hydrocarbon and natural gas realizations, partially offset by higher liquid hydrocarbon and natural gas sales volumes. On average, our net worldwide liquid hydrocarbon realizations were 35 percent lower in 2009 than in 2008 and our net worldwide natural gas realizations were 46 percent lower. Liquid hydrocarbon sales volumes in 2009 benefited from a full year production from both the Alvheim/Vilje development offshore Norway and the Neptune development in the Gulf of Mexico, which commenced production mid-year 2008. Natural gas sales volumes from Equatorial Guinea increased almost 16 percent from 2008 to 2009, more than making up for decreased sales as a result of our property divestitures in the Permian Basin of the U.S., Ireland and Norway. Because the majority of the natural gas sales increase was fixed-price sales to the LNG production facility in Equatorial Guinea, our average international natural gas realizations decreased by more than the market in general. Our share of the income ultimately generated by the subsequent export of LNG produced by EGHoldings, as well as methanol produced by AMPCO, is reflected in our Integrated Gas segment as discussed below.

	2009	2008
E&P Operating Statistics		
Net Liquid Hydrocarbon Sales (mbpd)[a]		
United States	64	63
Europe	92	55
Africa	87	87
Total International	179	142
Worldwide Continuing Operations	243	205
Discontinued Operations[b]	5	6
Worldwide	248	211
Natural Gas Sales (mmcfd)		
United States	373	448
Europe[c]	138	161
Africa	430	370
Total International	568	531
Worldwide Continuing Operations	941	979
Discontinued Operations[b]	17	37
Worldwide	958	1,016
Total Worldwide Sales (mboepd)		
Continuing Operations	400	369
Discontinued Operations[b]	7	12
Worldwide	407	381

	2009	2008
E&P Operating Statistics		
Average Realizations[(d)]		
Liquid Hydrocarbons (per bbl)		
United States	$ 54.67	$ 86.68
Europe	64.46	90.60
Africa	53.91	89.85
Total International	59.31	90.14
Worldwide Continuing Operations	58.09	89.07
Discontinued Operations[(b)]	56.47	96.41
Worldwide	$ 58.06	$ 89.29
Natural Gas (per mcf)		
United States	$ 4.14	$ 7.01
Europe	4.90	7.67
Africa	0.25	0.25
Total International	1.38	2.50
Worldwide Continuing Operations	2.47	4.56
Discontinued Operations[(b)]	8.54	9.62
Worldwide	$ 2.58	$ 4.75

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

(b) Our businesses in Ireland and Gabon were sold in 2009. All periods have been recast to reflect these businesses as discontinued operations.

(c) Includes natural gas acquired for injection and subsequent resale of 22 mmcfd and 32 mmcfd in 2009 and 2008.

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

E&P segment revenues included derivative losses of $13 million in 2009 and gains of $22 million in 2008. Excluded from E&P segment revenues were gains of $72 million in 2009 and $218 million in 2008 related to natural gas sales contracts in the U.K. that were accounted for as derivative instruments. These U.K contracts expired in September 2009.

OSM segment revenues decreased $455 million from 2008 to 2009. Revenues were impacted by net gains of $12 million in 2009 and $48 million in 2008 on derivative instruments, which expired December 2009. Excluding the derivatives, the decrease in revenue reflects the almost 40 percent decline in synthetic crude oil realizations. Synthetic crude oil sales volumes were consistent between the years.

RM&T segment revenues decreased $18,951 million from 2008 to 2009 matching relative price level changes. While our overall refined product sales volumes in 2009 were relatively unchanged compared to 2008, the level of average petroleum prices declined significantly as shown in Item 1. Business—Refining, Marketing and Transportation. The level of crude oil prices has a direct influence on our refined product prices. The table below shows the average annual refined product benchmark prices for our marketing area.

(Dollars per gallon)	2009	2008
Chicago Spot Unleaded regular gasoline	$1.68	$2.50
Chicago Spot Ultra-low sulfur diesel	$1.66	$2.95
U.S. Gulf Coast Spot Unleaded regular gasoline	$1.64	$2.48
U.S. Gulf Coast Spot Ultra-low sulfur diesel	$1.66	$2.93

Sales to related parties decreased in 2009 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 $467 million in 2009 from 2008 primarily as the result of lower commodity prices on the earnings of many of our equity investees in 2009 and the sale of our equity method investment in PTC during the fourth quarter of 2008.

Net gain on disposal of assets in 2009 includes our gain on the sale of our operated and a portion of our outside-operated Permian Basin producing assets in New Mexico and west Texas, plus sales of other oil and gas properties and retail stores. In 2008, we sold our outside-operated interests (24 percent of Heimdal field, 47 percent of Vale field and 20 percent of Skirne field) and associated undeveloped acreage in offshore Norway and our share of the PTC joint venture in 2008.

Cost of revenues decreased $19,117 million from 2008 to 2009. The largest decreases were in the RM&T segment and resulted from lower acquisition costs of crude oil. Acquisition costs for refinery charge and blendstocks and for purchased refined products also decreased. In our other segments, lower commodity prices and the related lower energy costs also contributed to the lower cost of revenues.

Depreciation, depletion and amortization ("DD&A") increased $494 million in 2009 from 2008. The increase in 2009 primarily relates to higher sales volumes, particularly from the Alvheim/Vilje development offshore Norway and the Neptune development in the Gulf of Mexico, both of which commenced production mid-year 2008.

Goodwill impairment expense of $1,412 million in 2008 relates to our OSM reporting unit. There were no such impairments in 2009. See Note 15 to the consolidated financial statements for further information about the impairment.

Net interest and other financial costs increased $121 million from 2008 to 2009. Interest income decreased due to substantially lower interest rates, although average cash balances were higher in 2009. While interest expense increased due to the February 2009 issuance of $1.5 billion in senior notes, increased capitalized interest related to our capital projects offset the impact. We recorded a writeoff of a portion of the contingent proceeds from the sale of the Corrib natural gas development (see Note 7 to the consolidated financial statements) in the fourth quarter of 2009 by $70 million on the basis of new public information regarding the pipeline that would transport gas from the Corrib development.

Provision for income taxes decreased $1,110 million from 2008 to 2009 primarily due to the reduction in pretax income. The effective rate, however, increased from 50 percent in 2008 to 66 percent in 2009. The effective tax rate is influenced by the geographical mix of income and related tax expense. In 2009 more income was generated in high tax jurisdictions than in 2008. Also contributing to the increase in the effective tax rate is the remeasurement of foreign currency denominated tax balances to U.S. dollars. In 2009 the remeasurement provided a $319 million tax charge compared to a $249 million tax benefit in 2008. See Note 11 to the consolidated financial statements.

Discontinued operations reflect the current year disposal of our E&P businesses in Ireland and Gabon and the historical results of those operations, net of tax, for all periods presented. See Note 7 to the consolidated financial statements.

Segment Results: 2009 compared to 2008

Segment income for 2009 and 2008 is summarized and reconciled to net income in the following table.

(In millions)	2009	2008
E&P		
United States	$ 55	$ 869
International	1,166	1,687
E&P segment	1,221	2,556
OSM	44	258
IG	90	302
RM&T	464	1,179
Segment income	1,819	4,295
Items not allocated to segments, net of income taxes:		
Corporate and other unallocated items	(422)	(75)
Foreign currency effects on tax balances	(319)	249
Impairments[a]	(45)	(1,437)
Gain on U.K. natural gas contracts[b]	37	111
Gain on disposal of assets	114	241
Discontinued operations	279	144
Net income	$1,463	$ 3,528

[a] Impairments in 2009 reflect $45 million ($70 million pretax) writeoff of a portion of the contingent proceeds from the sale of the Corrib natural gas development (see Note 7 to the consolidated financial statements) that was recorded the fourth quarter of 2009 on the basis of new public information regarding the pipeline that would transport gas from the Corrib development. Impairments in 2008 include a $1,412 million impairment of goodwill related to the OSM reporting unit (see Note 15 to the consolidated financial statements) and a $25 million after-tax impairment ($40 million pretax) related to our investments in ethanol producing facilities (see Note 13 to the consolidated financial statements).

[b] Amounts relate to natural gas contracts in the U. K. that are accounted for as derivative instruments and recorded at fair value.

United States E&P income decreased $814 million, or 94 percent, from 2008 to 2009. The majority of the income decrease was due to liquid hydrocarbon and natural gas realizations averaging almost 40 percent lower than in 2008, as well as lower natural gas sales volumes and higher DD&A, partially offset by lower operating costs and exploration expenses. Exploration expenses were $153 million for the year 2009, compared to $238 million for 2008, reflecting decreased geological and geophysical spending and lower exploration dry well expense.

International E&P income decreased $521 million, or 31 percent, from 2008 to 2009. The majority of the income decrease is tied to lower liquid hydrocarbon and natural gas realizations and overall higher DD&A, primarily associated with a full year of Alvheim production. The revenue impact of lower realizations was partially offset by improved sales volumes from Norway and Equatorial Guinea. Additionally, operating costs and exploration expenses were lower. Exploration expenses were $154 million for the full year 2009, compared to $251 million for 2008, reflecting lower dry well expense and decreased geological and geophysical spending.

OSM segment income decreased $214 million, or 83 percent, from 2008 to 2009. The majority of the decrease in income for 2009 was due to synthetic crude oil realizations averaging almost 40 percent lower than in 2008, partially offset by lower blendstock and energy costs. Results for 2008 included after-tax gains on crude oil derivative instruments of $32 million, while the impact of derivatives on the 2009 periods was not significant. Those derivative instruments expired December 2009 (see Item 7A. Quantitative and Qualitative Disclosures about Market Risk).

IG segment income decreased $212 million, or 70 percent, from 2008 to 2009. The decrease in income was primarily the result of lower realizations for LNG and methanol. As evidenced by higher sales volumes, strong operational reliability at the EG LNG facility throughout 2009 partially offset the impact of lower prices. The LNG production facility averaged higher than 95 percent operational availability during 2009. We hold a 60 percent interest in the facility.

RM&T segment income decreased $715 million, or 61 percent, from 2008 to 2009, primarily as a result of the decrease in our refining and wholesale marketing gross margin per gallon from 11.66 cents in 2008 to 6.10 cents in 2009. The gross margin decline is a result of a 52 percent narrowing of the sweet/sour differential, thereby increasing the relative cost of crude processed by our refineries. The narrowing of the sweet/sour differential resulted from a variety of worldwide economic and petroleum industry related factors primarily related to lower hydrocarbon demand.

Included in the refining and wholesale marketing gross margins were pretax derivative losses of $83 million in 2009 and $87 million in 2008. For a more complete explanation of our strategies to manage market risk related to commodity prices, see Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

We averaged 957 mbpd of crude oil throughput in 2009 and 944 mbpd in 2008. Total refinery throughputs averaged 1,153 mbpd in 2009 compared to 1,151 mbpd in 2008. Crude and total throughputs were lower in 2008 than in 2009 in part due to the impact that hurricanes and other weather related events had on our operations in 2008.

The following table includes certain key operating statistics for the RM&T segment for 2009 and 2008.

RM&T Operating Statistics	2009	2008
Refining and wholesale marketing gross margin *(Dollars per gallon)*[(a)]	$0.0610	$0.1166
Refined products sales volumes *(Thousands of barrels per day)*	1,378	1,352

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

Consolidated Results of Operations: 2008 compared to 2007

Revenues are summarized in the following table.

(In millions)	2008	2007
E&P	$12,047	$ 8,699
OSM	1,122	221
IG	93	218
RM&T	64,481	56,075
Segment revenues	77,743	65,213
Elimination of intersegment revenues	(1,207)	(885)
Gain (loss) on U.K. natural gas contracts	218	(232)
Total revenues	$76,754	$64,096
Items included in both revenues and costs:		
Consumer excise taxes on petroleum products and merchandise	$ 5,065	$ 5,163

E&P segment revenues increased $3,348 million from 2007 to 2008. Higher average liquid hydrocarbon and natural gas realizations account for over 70 percent of the revenue increase. Liquid hydrocarbon and natural gas sales volumes were also higher in 2008 than 2007. Sales volumes also benefited from a full year of natural gas sales to the Equatorial Guinea LNG production facility, which we co-own. Beginning mid-year, both the Alvheim/Vilje development offshore Norway and the Neptune development in the Gulf of Mexico contributed particularly to the liquid hydrocarbon sales increase. Because the majority of the natural gas sales increase was fixed-price sales to the LNG production facility in Equatorial Guinea, our average international natural gas realizations decreased. Our share of the income ultimately generated by the subsequent export of LNG produced by EGHoldings, as well as methanol produced by AMPCO is reflected in our Integrated Gas segment as discussed below.

	2008	2007
E&P Operating Statistics		
Net Liquid Hydrocarbon Sales (mbpd)[a]		
United States	63	64
Europe	55	33
Africa	87	90
Total International	142	123
Worldwide Continuing Operations	205	187
Discontinued Operations[b]	6	10
Worldwide	211	197
Natural Gas Sales (mmcfd)		
United States	448	477
Europe[c]	161	177
Africa	370	232
Total International	531	409
Worldwide Continuing Operations	979	886
Discontinued Operations[b]	37	39
Worldwide	1,016	925
Total Worldwide Sales (mboepd)		
Continuing Operations	369	334
Discontinued Operations[b]	12	17
Worldwide	381	351

	2008	2007
E&P Operating Statistics		
Average Realizations[d]		
Liquid Hydrocarbons (per bbl)		
United States	$86.68	$60.15
Europe	90.60	70.31
Africa	89.85	65.41
Total International	90.14	66.74
Worldwide Continuing Operations	89.07	64.47
Discontinued Operations[b]	96.41	72.19
Worldwide	$89.29	$64.86
Natural Gas (per mcf)		
United States	$ 7.01	$ 5.73
Europe	7.67	6.49
Africa	0.25	0.25
Total International	2.50	2.96
Worldwide Continuing Operations	4.56	4.45
Discontinued Operations[b]	9.62	6.71
Worldwide	$ 4.75	$ 4.54

(a) Includes crude oil, condensate and natural gas liquids. The amounts correspond with the basis for fiscal settlements with governments, representing equity tanker liftings and direct deliveries of liquid hydrocarbons.
(b) Our businesses in Ireland and Gabon were sold in 2009. All periods have been recast to reflect these businesses as discontinued operations.
(c) Includes natural gas acquired for injection and subsequent resale of 32 mmcfd and 47 mmcfd in 2008 and 2007.
(d) Excludes gains and losses on derivative instruments and the unrealized effects of U.K. natural gas contracts that are accounted for as derivatives.

E&P segment revenues included derivative gains of $22 million in 2008 and losses of $15 million in 2007. Excluded from E&P segment revenues were gains of $218 million in 2008 and losses of $232 million in 2007 related to natural gas sales contracts in the U.K. that were accounted for as derivative instruments.

OSM segment revenues increased $901 million from 2007 to 2008, reflecting a full year of operations in 2008. Revenues were impacted by net gains in 2008 and net losses in 2007 on derivative instruments, which expire

December 2009, that were held by Western at the acquisition date and intended to mitigate price risk related to future sales of synthetic crude oil. The 2008 net gain of $48 million included realized losses of $72 million and unrealized gains of $120 million, while less than $1 million of the $53 million net loss in 2007 was realized. Additionally, revenues were negatively impacted by reliability issues and the implementation of a revised tailings management plan that impacted ore grade. Sales of synthetic crude oil averaged 32 mbpd at an average realized price of $91.90 per barrel compared to a $71.07 average realized price for the period from the October 18, 2007, acquisition date through December of 2007.

RM&T segment revenues increased $8,406 million from 2007 to 2008. Higher refined product selling prices were realized in 2008, but lower sales volumes partially offset the price impact.

Income from equity method investments increased $220 million from 2007 to 2008. The Equatorial Guinea LNG production facility operated for the full year of 2008, accounting for most of the increased income, with 54 cargoes delivered in 2008 compared to 24 in 2007. In addition, there was an $81 million increase in PTC income due to higher retail margins. Offsetting these increases was the $40 million pretax impairment of our equity investment in two ethanol production facilities, losses generated by one of those facilities and lower income from AMPCO. AMPCO sales volumes and realized prices were lower in 2008 due to temporary reductions in available feedstock gas and plant reliability problems.

Net gain on disposal of assets increased $387 million as a result of the review of our portfolio of assets that commenced in 2008. We sold our outside-operated interests (24 percent of Heimdal field, 47 percent of Vale field and 20 percent of Skirne field) and associated undeveloped acreage in offshore Norway and our share of the PTC joint venture in 2008. Property sales in 2007, primarily related to sales of individual producing properties and retail outlets were not significant.

Cost of revenues increased $10,548 million from 2007 to 2008. The increases were primarily in the RM&T segment and resulted from increases in acquisition costs of crude oil. Acquisition costs for refinery charge and blendstocks and for purchased refined products also increased, but the impact of this increase was partially offset by the impact of lower refinery throughput.

Depreciation, depletion and amortization ("DD&A") increased $565 million in 2008 from 2007. The increase in 2008 primarily relates to new assets. Our oil sands assets operated for the full year of 2008 and two significant offshore developments, Alvheim/Vilje offshore Norway and Neptune in the Gulf of Mexico, began operating at mid-year.

Goodwill impairment expense of $1,412 million relates to our OSM reporting unit. During the fourth quarter of 2008, we tested our OSM reporting unit's goodwill for impairment and upon allocating fair value among the reporting unit's assets, there was no remaining implied fair value of goodwill as of December 31, 2008. See Note 15 to the consolidated financial statements for further information about the impairment.

Net interest and other financial income or costs reflected $28 million in costs for 2008 and $33 million of income for 2007. Interest income decreased due to lower interest rates and average cash balances during 2008. While interest expense also increased due to a higher level of short-term commercial paper borrowings throughout 2008 a similar increase in capitalized interest related to our capital projects offset the impact.

Gain on foreign currency derivative instruments in 2007 represented gains on foreign currency derivative instruments entered to limit our exposure to changes in the Canadian dollar exchange rate related to the cash portion of the purchase price for Western. These derivative instruments were settled on October 17, 2007.

Provision for income taxes increased $565 million from 2007 to 2008, a 20 percent increase, although income from continuing operations before income taxes increased only $183 million, or 3 percent. The effective tax rate in 2008 was impacted by the goodwill impairment which cannot be deducted for purposes of calculating income tax. The consolidated effective tax rate was also influenced by the geographical mix of income and related tax expense. Partially offsetting the effective tax rate increase caused by the goodwill impairment and income mix were benefits related to the reversal of the valuation allowance on the Norwegian net operating loss carryforwards and a $249 million benefit from the remeasurement of foreign currency denominated deferred tax balances. See Note 11 to the consolidated financial statements.

Discontinued operations reflect the current year disposal of our E&P businesses in Ireland and Gabon (see Note 7) and the historical results of those operations, net of tax, for all periods presented.

Segment Results: 2008 compared to 2007

Segment income for 2008 and 2007 is summarized and reconciled to net income in the following table.

(In millions)	2008	2007
E&P		
United States	$ 869	$ 623
International	1,687	929
E&P segment	2,556	1,552
OSM	258	(63)
IG	302	132
RM&T	1,179	2,077
Segment income	4,295	3,698
Items not allocated to segments, net of income taxes:		
Corporate and other unallocated items	(75)	(128)
Foreign currency effects on tax balances	249	19
Impairments[a]	(1,437)	-
Gain (loss) on U.K. natural gas contracts[b]	111	(118)
Gain on disposal of assets	241	-
Gain on foreign currency derivative instruments	-	112
Deferred income taxes-tax legislation changes	-	193
Loss on early extinguishment of debt	-	(10)
Discontinued operations	144	190
Net income	$ 3,528	$3,956

(a) Impairments in 2008 include a $1,412 million impairment of goodwill related to the OSM reporting unit (see Note 15 to the consolidated financial statements) and a $25 million after-tax impairment ($40 million pretax) related to our investments in ethanol producing facilities (see Note 13 to the consolidated financial statements).

(b) Amounts relate to natural gas contracts in the U. K. that are accounted for as derivative instruments and recorded at fair value.

United States E&P income increased $246 million, or 39 percent, from 2007 to 2008. The majority of the increase from year to year was due to overall higher average liquid hydrocarbon and natural gas realizations with relatively flat sales volumes. Partially offsetting the benefits of higher prices were increases in production taxes, operating expenses, DD&A and income taxes. Exploration expenses were $238 million for 2008, lower than $274 million in 2007.

International E&P income increased $758 million, or 82 percent, from 2007 to 2008 primarily due to higher average liquid hydrocarbon realizations and higher sales volumes for both liquid hydrocarbons and natural gas. Natural gas realizations were slightly lower because a significant portion of the natural gas sales volume increase related to that sold in Equatorial Guinea to the LNG production facility at a fixed price. Operating expenses and DD&A, associated with production from new developments, and income taxes also increased during 2008.

OSM segment income reported income of $258 million in 2008 as compared to a loss of $63 million in 2007. An after-tax gain on crude oil derivative instruments of $32 million was included in 2008 income while an after-tax loss of $40 million was recorded in 2007 (see Item 7A. Quantitative and Qualitative Disclosures about Market Risk). Results for 2008 include a full year of operations in comparison to two and one-half months of operation in 2007. Bitumen was produced at an average rate of 25 mbpd in 2008. Production and processing levels were adversely impacted by planned and unplanned maintenance, reliability issues and the implementation of a revised tailings management plan that impacted ore grade, which also increased operating costs.

IG segment income increased $170 million, or 129 percent, in 2008 from 2007. The increase in income was primarily related to a full year of operation of the LNG production facility in Equatorial Guinea, which commenced operations in May 2007. We hold a 60 percent interest in the facility. Segment expenses increased slightly in 2008 as we continue to develop new technologies. In 2008, we spent $92 million on gas commercialization technologies, including completing construction of a Gas-To-Fuels™ demonstration plant. Such expense in 2007 was $42 million.

RM&T segment income decreased $898 million from 2007 to 2008 primarily a result of a decrease in our refining and wholesale marketing gross margin per gallon from 18.48 cents in 2007 to 11.66 cents in 2008. The refining and wholesale marketing gross margin decline was consistent with the market indicators (crack spreads) in the Midwest and Gulf Coast regions. In addition, manufacturing expenses were higher in 2008 due primarily to higher energy costs and maintenance activities.

Included in the refining and wholesale marketing gross margins were pretax derivative losses of $87 million in 2008 and $899 million in 2007. The variance primarily reflects falling crude futures prices in the second half of 2008, as well as the fact that we reduced our use of derivatives to manage domestic crude oil acquisition price risk. For a more complete explanation of our strategies to manage market risk related to commodity prices, see Quantitative and Qualitative Disclosures about Market Risk.

We averaged 944 mbpd of crude oil throughput in 2008 and 1,010 mbpd in 2007. Total refinery throughputs averaged 1,151 mbpd in 2008 compared to 1,224 mbpd in 2007. Crude and total throughputs were lower in 2008 than in 2007 in part due to the impact hurricanes and other weather related events had on our operations in 2008.

The following table includes certain key operating statistics for the RM&T segment for 2008 and 2007.

RM&T Operating Statistics	2008	2007
Refining and wholesale marketing gross margin *(Dollars per gallon)*[(a)]	$0.1166	$0.1848
Refined products sales volumes *(Thousands of barrels per day)*	1,352	1,410

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

Management's Discussion and Analysis of Financial Condition, Cash Flows and Liquidity

Cash Flows

Net cash provided from operating activities totaled $5,268 million in 2009 compared to $6,752 million in 2008 and $5,900 million in 2007. The $1,484 million decrease in 2009 reflects the impact of lower average realized prices in 2009. The $852 million increase in 2008 primarily reflects the impact of higher average realized prices in 2008.

Net cash used in investing activities totaled $5,238 million in 2009, compared with $5,405 million in 2008 and $7,481 million in 2007. Significant investing activities include additions to property, plant and equipment, asset disposals and an acquisition of a business in 2007.

The most significant additions to property, plant and equipment relate to our long-term projects, which cross several years. In our E&P segment, exploration and development projects in Angola impacted all three years. Development and completion of the Alvheim/Vilje project affected 2007 and 2008, with other developments in the area in 2009. Beginning in 2008, spending on U.S. exploration and development projects in the Gulf of Mexico and unconventional resource plays became a more significant portion of our additions to property, plant and equipment. In the OSM segment, the AOSP Expansion 1 began in 2008 and continued through 2009. In our RM&T segment, the expansion of our Garyville, Louisiana, refinery affected all years. Also in RM&T, the expansion and upgrading of our Detroit, Michigan refinery commenced with front-end engineering and design work in 2007 and construction in 2008 and 2009.

We have revised prior year amounts of capital expenditures in the consolidated statement of cash flows. The consolidated statements of cash flows excludes changes to the consolidated balance sheets that did not affect cash. A reconciliation of this amount to the reported capital expenditures follows for all years presented:

(in millions)	2009	2008	2007
Additions to property, plant and equipment	$6,231	$6,989	$3,757
Change in capital accruals	(343)	30	621
Discontinued operations	84	127	88
Capital expenditures	$5,972	$7,146	$4,466

Acquisitions in 2007 consist of the $3,907 million cash portion of the Western acquisition purchase price, net of the $44 million of cash acquired. See Note 6 to the consolidated financial statements for more information about the Western acquisition.

Disposal of assets totaled $865 million, $999 million and $137 million in 2009, 2008 and 2007. In 2009, we sold all of our operated and outside-operated interests in Ireland and Gabon, reporting the disposals as discontinued operations. We also sold our operated and a portion of our outside-operated Permian Basin producing assets in New Mexico and west Texas. In 2008, disposal of assets included proceeds from the sale of our outside-operated interests and related undeveloped acreage in Norway and our share of PTC. In 2007, we sold our interests in two LNG tankers in Alaska. Disposals for all years included proceeds from the sale of various domestic producing properties and SSA stores. See Note 7 to the consolidated financial statements for more information about dispositions.

Net cash provided from financing activities totaled $724 million in 2009, compared with cash used in financing activities of $1,193 million in 2008 and cash provided from financing activities of $184 million in 2007. Sources of cash included the issuance of $1.5 billion in senior notes in 2009, the issuance of $1.0 billion in senior notes in 2008 and the issuance of $1.5 billion in senior notes and borrowings of $578 million from the Norwegian export credit agency in 2007. Repayments of debt and common stock repurchases under our share repurchase plan were significant uses of cash in 2008 and 2007, while dividend payments impacted every year.

Significant noncash transactions during 2007 included the issuance of $1.0 billion of 5.125 percent Fixed Rate Revenue Bonds (Marathon Oil Corporation Project) Series 2007A, with a maturity date of June 1, 2037. The proceeds from the bonds, along with interest income, were held in trust and were disbursed to us for reimbursement of expenditures related to our Garyville, Louisiana refinery expansion over the course of the construction project. Until all trusteed funds were disbursed, the balance was reported as other noncurrent assets in our consolidated balance sheet. As of December 31, 2009, we have received all funds from this financing.

Liquidity and Capital Resources

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

Capital Resources

Credit Arrangements and Borrowings

At December 31, 2009, we had $8,436 million in long term debt outstanding. Our senior unsecured debt is currently rated investment grade by Standard and Poor's Corporation, Moody's Investor Services, Inc. and Fitch Ratings with ratings of BBB+, Baa1, and BBB+, all with stable outlook. Should one or all of these agencies decide to downgrade our ratings, it could become more difficult and more costly for us to issue new debt or commercial paper. We do not have any ratings triggers on any of our corporate debt that would cause an event of default in the case of a downgrade of our credit ratings.

At December 31, 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.

Shelf Registration

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

Cash-Adjusted Debt-To-Capital Ratio

Our cash-adjusted debt-to-capital ratio (total debt-minus-cash to total debt-plus-equity-minus-cash) was 23 percent and 22 percent at December 31, 2009 and 2008. This includes $340 million of debt at December 31, 2009 that is serviced by United States Steel Corporation ("United States Steel").

(Dollars in millions)	2009	2008
Long-term debt due within one year	$ 96	$ 98
Long-term debt	8,436	7,087
Total debt	$ 8,532	$ 7,185
Cash	$ 2,057	$ 1,285
Trusteed funds from revenue bonds[(a)]	$ -	$ 16
Equity	$ 21,910	$ 21,409
Calculation:		
Total debt	$ 8,532	$ 7,185
Minus cash	2,057	1,285
Minus trusteed funds from revenue bonds	-	16
Total debt minus cash	6,475	5,884
Total debt	8,532	7,185
Plus equity	21,910	21,409
Minus cash	2,057	1,285
Minus trusteed funds from revenue bonds	-	16
Total debt plus equity minus cash	$ 28,385	$ 27,293
Cash-adjusted debt-to-capital ratio	23%	22%

(a) Following the issuance of the $1.0 billion of revenue bonds by the Parish of St. John the Baptist, the proceeds were trusteed and were disbursed to us upon our request for reimbursement of expenditures related to the Garyville refinery expansion. The trusteed funds were reflected as other noncurrent assets in the accompanying consolidated balance sheet as of December 31, 2008.

Capital Requirements

Capital Spending

We have approved a capital, investment and exploration budget of $5,148 million for 2010, which represents a 17 percent decrease from our 2009 spending. Additional details related to the 2010 budget are discussed in Outlook.

Other Expected Cash Outflows

We plan to make contributions of up to $17 million to fund pension plans during 2010. As of December 31, 2009, $96 million of our long-term debt is due in the next twelve months.

Dividends of $0.96 per common share or $679 million were paid during 2009. On February 1, 2010, we announced that our Board of Directors had declared a dividend of $0.24 cents per share on Marathon common stock, payable March 10, 2010, to stockholders of record at the close of business on February 17, 2010.

Share Repurchase Program

Since January 2006, our Board of Directors has authorized a common share repurchase program totaling $5 billion. As of December 31, 2009, we had repurchased 66 million common shares at a cost of $2,922 million. We have not made any purchases under the program since August 2008. Purchases under the program may be in either open market transactions, including block purchases, or in privately negotiated transactions. This program may be changed based upon our financial condition or changes in market conditions and is subject to termination prior to completion. The program's authorization does not include specific price targets or timetables. The timing of purchases under the program will be influenced by cash generated from operations, proceeds from potential asset sales and cash from available borrowings.

Our opinions concerning liquidity and our ability to avail ourselves in the future of the financing options mentioned in the above forward-looking statements are based on currently available information. If this information proves to be inaccurate, future availability of financing may be adversely affected. Factors that affect the availability of financing include our performance (as measured by various factors including cash provided from operating activities), the state of worldwide debt and equity markets, investor perceptions and expectations of past and future performance, the global financial climate, and, in particular, with respect to borrowings, the levels of our outstanding debt and credit ratings by rating agencies. The discussion of liquidity above also contains forward-looking statements regarding expected capital, investment and exploration spending and a review of our portfolio of assets. The forward-looking statements about our capital, investment and exploration budget are based on current expectations, estimates and projections and are not guarantees of future performance. Actual results may differ materially from these expectations, estimates and projections and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. Some factors that could cause actual results to differ materially include prices of and demand for liquid hydrocarbons, natural gas and refined products, actions of competitors, disruptions or interruptions of our production, oil sands mining and bitumen upgrading or refining operations due to the shortage of skilled labor and unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response, and other operating and economic considerations. The forward-looking statements about our common share repurchase program are based on current expectations, estimates and projections and are not guarantees of future performance. Actual results may differ materially from these expectations, estimates and projections and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. Some factors that could cause actual results to differ materially are changes in prices of and demand for crude oil, natural gas and refined products, actions of competitors, disruptions or interruptions of our production or refining operations due to unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response, and other operating and economic considerations.

Contractual Cash Obligations

The table below provides aggregated information on our consolidated obligations to make future payments under existing contracts as of December 31, 2009.

(In millions)	Total	2010	2011-2012	2013-2014	Later Years
Long-term debt (excludes interest)[a] [b]	$ 8,184	$ 68	$ 1,664	$ 1,044	$ 5,408
Sale-leaseback financing[a]	33	11	22	-	-
Capital lease obligations[a]	670	35	81	88	466
Operating lease obligations[a]	909	160	251	186	312
Operating lease obligations under sublease[a]	16	5	11	-	-
Purchase obligations:					
Crude oil, feedstock, refined product and ethanol contracts[c]	19,527	12,136	6,843	431	117
Transportation and related contracts	2,354	395	417	260	1,282
Contracts to acquire property, plant and equipment	2,938	1,466	1,380	73	19
LNG terminal operating costs[d]	143	13	25	25	80
Service and materials contracts[e]	2,261	429	537	433	862
Unconditional purchase obligations[f]	47	8	16	16	7
Commitments for oil and gas exploration (non-capital)[g]	43	29	7	1	6
Total purchase obligations	27,313	14,476	9,225	1,239	2,373
Other long-term liabilities reported in the consolidated balance sheet[h]	2,308	80	643	560	1,025
Total contractual cash obligations[i] [j]	$ 39,433	$ 14,835	$ 11,897	$ 3,117	$ 9,584

(a) Upon the USX Separation, United States Steel assumed certain debt and lease obligations, including $286 million of long-term debt obligations related to industrial revenue bonds. The Financial Matters Agreement provides that, on or before the tenth anniversary of the USX Separation, United States Steel will provide for Marathon's discharge from any remaining liability under any of the assumed industrial revenue bonds. Such amounts are included in the above table because we remain primarily liable.

(b) We anticipate cash payments for interest of $500 million for 2010, $922 million for 2011-2012, $731 million for 2013-2014 and $3,474 million for the remaining years for a total of $5,627 million. Of these, we anticipate cash payments for interest of $16 million for 2010, $22 million for 2011-2012, $16 million for 2013-2014 and $108 million for the later years to be made by United States Steel.

(c) The majority of these contractual obligations as of December 31, 2009 relate to contracts to be satisfied within the first 180 days of 2010. These contracts include variable price arrangements.

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

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

(f) We are a party to a long-term transportation services agreement with Alliance Pipeline. This agreement was used by Alliance Pipeline to secure its financing. This arrangement represents an indirect guarantee of indebtedness. Therefore, this amount has also been disclosed as a guarantee.

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

(h) Primarily includes obligations for pension and other postretirement benefits including medical and life insurance. We have estimated projected funding requirements through 2019. Also includes amounts for uncertain tax positions.

(i) Includes $362 million of contractual cash obligations that have been assumed by United States Steel. See Item 7. Management's Discussion and Analysis of Financial Condition, Cash Flows and Liquidity – Obligations Associated with the Separation of United States Steel.

(j) This table does not include the estimated discounted liability for dismantlement, abandonment and restoration costs of oil and gas properties of $1,102 million. See Note 20 to the consolidated financial statements.

Transactions with Related Parties

We own a 63 percent working interest in the Alba field offshore Equatorial Guinea. Onshore Equatorial Guinea, we own a 52 percent interest in an LPG processing plant, a 60 percent interest in an LNG production facility and a 45 percent interest in a methanol production plant, each through equity method investees. We sell our natural gas from the Alba field to these equity method investees as the feedstock for their production processes. The methanol that is produced is then sold through another equity method investee.

Sales of refined petroleum products to our 50 percent equity method investee, PTC, which was sold in October 2008, accounted for 2.5 percent or less of our total sales revenue for 2008 and 2007. We believe that these transactions with related parties have been conducted under terms comparable to those with unrelated parties

Off-Balance Sheet Arrangements

Off-balance sheet arrangements comprise those arrangements that may potentially impact our liquidity, capital resources and results of operations, even though such arrangements are not recorded as liabilities under accounting principles generally accepted in the U.S. Although off-balance sheet arrangements serve a variety of our business purposes, we are not dependent on these arrangements to maintain our liquidity and capital resources, and we are not aware of any circumstances that are reasonably likely to cause the off-balance sheet arrangements to have a material adverse effect on liquidity and capital resources.

We have provided various guarantees related to equity method investees, United States Steel and others. These arrangements are described in Note 26 to the consolidated financial statements.

Obligations Associated with the Separation of United States Steel

We remain obligated (primarily or contingently) for certain debt and other financial arrangements for which United States Steel has assumed responsibility for repayment under the terms of the USX Separation. United States Steel's obligations to us are general unsecured obligations that rank equal to United States Steel's accounts payable and other general unsecured obligations. If United States Steel fails to satisfy these obligations, we would become responsible for repayment. Under the Financial Matters Agreement, United States Steel has all of the existing contractual rights under the leases assumed from us, including all rights related to purchase options, prepayments or the grant or release of security interests. However, United States Steel has no right to increase amounts due under or lengthen the term of any of the assumed leases, other than extensions set forth in the terms of the assumed leases.

As of December 31, 2009, we have identified the following obligations that have been assumed by United States Steel:

- $286 million of industrial revenue bonds related to environmental improvement projects for current and former United States Steel facilities, with maturities ranging from 2011 through 2033. Accrued interest payable on these bonds was $6 million at December 31, 2009. We anticipate United States Steel will make future interest payments of $16 million for 2010, $22 million for 2011-2012, $16 million for 2013-2014 and $108 million for the later years.
- $29 million of sale-leaseback financing under a lease for equipment at United States Steel's Fairfield Works, with a term extending to 2012, subject to extensions. There was no accrued interest payable on this financing at December 31, 2009.
- $25 million of obligations under a lease for equipment at United States Steel's Clairton coke-making facility, with a term extending to 2012. There was no accrued interest payable on this financing at December 31, 2009.
- $16 million of operating lease obligations, all of which was assumed by purchasers of major equipment used in plants and operations divested by United States Steel.
- A guarantee with respect to all obligations of United States Steel to the limited partners of the Clairton 1314B Partnership, L.P., which was terminated on October 31, 2008. Upon termination of the partnership, we were not released from our obligations under guarantee. United States Steel has reported that it currently has no unpaid outstanding obligations to the limited partners. See Note 26 to the consolidated financial statements.

Of the total $362 million, obligations of $346 million and corresponding receivables from United States Steel were recorded on our consolidated balance sheet as of December 31, 2009, (current portion—$22 million; long-term portion—$324 million). The remaining $16 million was related to off-balance sheet arrangements and contingent liabilities of United States Steel.

In its Form 10-K for the year ended December 31, 2009, United States Steel management stated that it believes its liquidity will be adequate to satisfy its obligations for the foreseeable future. During 2009, United States Steel undertook certain plans and actions designed to preserve and enhance its liquidity and financial flexibility, including the sale of its common stock and issuance of senior convertible notes due 2014 for net proceeds of approximately $1,496 million. During the fourth quarter of 2009, United States Steel refinanced $129 million of certain debt for which we were liable; as a direct result of the refinancing, we are no longer liable for that $129 million. United States Steel's senior unsecured debt ratings are BB by Standard and Poor's Corporation, Ba3 by Moody's Investment Service, Inc. and BB+ by Fitch Ratings. The ratings listed reflect a Fitch downgrade from BBB- to BB+ in January 2010.

Outlook

Our Board of Directors approved a capital, investment and exploration budget of $5,148 million for 2010, which includes budgeted capital expenditures of $4,863 million. This represents a 17 percent decrease from 2009 spending. The focus of our 2010 budget is on exploration and production activities, with an emphasis on ongoing development projects, certain potentially significant exploration wells and growing our presence in unconventional resource plays.

Exploration and Production

The worldwide exploration and production budget for 2010 is $2,868 million, of which $1,023 million is designated for our global exploration drilling program. A primary focus in 2010 is the deepwater Gulf of Mexico, where we plan to drill three or four significant wells. We have also targeted spending for Indonesia, where we plan to drill two potentially high-reward, but also high-risk, deepwater wells in 2010. Additionally, we anticipate drilling or participating in approximately 20 to 30 wells in emerging North American resource plays – the Marcellus Shale in Pennsylvania/West Virginia, the Woodford Shale in Oklahoma and the Haynesville/Bossier play in Texas – and approximately 10 to 15 onshore conventional wells in the Lower 48 in 2010.

This year's production budget of $1,845 million is concentrated on three key oil projects: North Dakota's Bakken Shale oil play, where we plan to drill or participate in approximately 75 wells; offshore Norway, where we plan further drilling or development on satellite fields surrounding the Alvheim/Vilje development, such as the Gudrun field; and offshore Angola, where deepwater PSVM development on Block 31 is under way. A total of 48 production and injection wells are planned at the PSVM, with the first three to four development wells planned in 2010. First production is anticipated in late 2011 to early 2012. Other discoveries on Angola Block 31 comprise potential development areas in the southeast and middle portions of the block and eight of the Block 32 discoveries form another potential development in the eastern area of that block. We expect first production on Block 32 in 2015-2016.

Additionally, in the Gulf of Mexico, we are winding down spending on the Droshky development, in which we own a 100 percent working interest while continuing work on the Ozona development. First production from Droshky is targeted for mid-2010. Initial production from Ozona, where we hold a 68 percent working interest, is expected in late 2011. We also plan to drill or participate in approximately 100 conventional development wells onshore U.S. in 2010.

The above discussion includes forward-looking statements with respect to anticipated future exploratory and development drilling, investments in new resource plays and development projects, the timing of production from the Droshky and Ozona developments in the Gulf of Mexico, the Faregh Phase II Gas Plant, the PVSM development on Block 31 offshore Angola, Block 32 and other possible developments. Some factors which 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, 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 or permits. The offshore developments could further be affected by presently known data concerning size and character of reservoirs, economic recoverability, future drilling success and production experience. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Oil Sands Mining

The budget includes $668 million for the Oil Sands Mining segment in 2010, down 32 percent as AOSP Expansion 1 approaches completion. Expansion 1, which includes construction of mining and extraction facilities at the Jackpine mine, new treatment facilities at the existing Muskeg River mine, addition of a new processing train at the Scotford upgrading facility and development of related infrastructure, is on track and anticipated to begin mining operations in the second half of 2010, and upgrader operations in late 2010 or early 2011. When Expansion 1 is complete, we will have more than 50 mbpd of production and upgrading capacity in the Canadian oil sands. The timing and scope of potential future expansions and debottlenecking opportunities on existing operations remain under review.

Beginning late in the first quarter of 2010 and continuing into the second quarter, the existing AOSP mine and upgrader operations will undergo a scheduled turnaround. The last scheduled turnaround occurred in 2006. Production is planned to be curtailed for approximately 60 to 70 days, during which the facilities will be completely shutdown for approximately two-thirds of the time. We expect our net cost of the turnaround to be approximately $85 to $120 million. Additional tie-ins and pipeline commissioning work related to the Expansion 1 will occur during this period, but such costs are included in the Expansion 1 capital budget.

Evaluation of the AOSP Quest Carbon Capture and Storage ("CCS") project continues in 2010. A final investment decision on the Quest CCS project will be made at a later date, and is subject to regulatory approvals, stakeholder engagement, detailed engineering studies, as well as a final joint venture partner agreement.

The above discussion includes forward-looking statements with respect to anticipated completion of the AOSP Expansion 1 and the planned turnaround at the AOSP mine and upgrader. Factors which could affect these 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.

Refining, Marketing and Transportation

The 2010 budget includes $1,114 million for RM&T segment projects. With the completion of the Garyville refinery expansion in 2009, budgeted spending is almost half what it was for 2009. As the new units comprising the Garyville refinery expansion reach full capacity utilization, we will have the capability to increase our relative distillate production capacity.

Continuation of the Detroit refinery heavy oil upgrading and expansion project accounts for about 36 percent of the budget. The Detroit project when finished will increase the refinery's heavy oil upgrading capacity, including Canadian bitumen blends, by about 80 mbpd, and will increase its total crude oil refining capacity by 10 percent. Through the Garyville and Detroit refinery investments, we expect to more than double our coking capacity by 2012, which should lead to lower feedstock costs and increased margins.

In early January 2010, we began an extended turnaround at the 256 mbpd base refinery in Garyville (the new expansion refinery will be operating during the time of the turnaround at the base refinery). The entire facility (base plus expansion) is expected to reach full refining capacity of 436 mbpd by the second quarter of 2010. Total expense from turnarounds and major maintenance activities is expected to increase by approximately $100 million pretax in the first quarter of 2010 compared to first quarter 2009, primarily due to the extent of the Garyville turnaround and major maintenance activities.

The remainder of the budget is allocated to maintaining facilities and meeting regulatory requirements, notably the Mobile Source Air Toxics ("MSAT II") regulations that will be effective at the beginning of 2011.

The above discussion includes forward-looking statements concerning the Detroit refinery heavy oil upgrading and expansion project, expected turnaround expenditures and MSAT II regulations compliance costs. Some factors that could affect the Detroit and MSAT II projects include transportation logistics, availability of materials and labor, unforeseen hazards such as weather conditions, 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

Although we have not budgeted for any capital spending for our Integrated Gas segment in 2010, we will continue non-capital spending in pursuit of the development of new technologies to supply new energy sources. We are evaluating the commercialization of our Gas-to-Fuels ("GTF™") technology and are pursuing other technologies focused on reducing the processing and transportation costs of natural gas.

The above discussion contains forward looking statements with respect to the potential commercialization of our GTF™ technology. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Corporate and Other

The remaining $498 million of our 2010 budget relates to capitalized interest and corporate activities.

The net income tax liabilities of our OSM operations are denominated in Canadian dollars and must be remeasured to U.S. dollars each reporting period. At year end we took steps, as permitted under Canadian tax rules, which will enable us to convert these liabilities during the first half of 2010 to be denominated in U.S. dollars and thereby eliminate exposure to foreign currency exchange rate changes on our net deferred tax liability related to OSM operations from that point forward.

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

Management's Discussion and Analysis of Environmental Matters, Litigation and Contingencies

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

Legislation and regulations pertaining to climate change and greenhouse gas emissions have the potential to materially adversely impact our business, financial condition, results of operations and cash flow, including costs of compliance and permitting delays. The extent and magnitude of these adverse impacts cannot be reliably or accurately estimated at this time because specific regulatory and legislative requirements have not been finalized and uncertainty exists with respect to the measures being considered, the costs and the time frames for compliance, and our ability to pass compliance costs on to our customers. For additional information see Item 1A. Risk Factors.

Our environmental expenditures[a] for each of the last three years were:

(In millions)	2009	2008	2007
Capital	$ 399	$ 421	$ 199
Compliance			
Operating and maintenance	373	379	287
Remediation[b]	29	26	25
Total	$ 801	$ 826	$ 511

(a) Amounts are determined based on American Petroleum Institute survey guidelines regarding the definition of environmental expenditures.

(b) These amounts include spending charged against remediation reserves, where permissible, but exclude non-cash provisions recorded for environmental remediation.

Our environmental capital expenditures accounted for seven percent of capital expenditures for continuing operations in 2009, six percent in 2008 and four percent in 2007.

We accrue for environmental remediation activities when the responsibility to remediate is probable and the amount of associated costs can be reasonably estimated. As environmental remediation matters proceed toward ultimate resolution or as additional remediation obligations arise, charges in excess of those previously accrued may be required.

New or expanded environmental requirements, which could increase our environmental costs, may arise in the future. We comply with all legal requirements regarding the environment, but since not all of them are fixed or presently determinable (even under existing legislation) and may be affected by future legislation or regulations, it is not possible to predict all of the ultimate costs of compliance, including remediation costs that may be incurred and penalties that may be imposed.

Our environmental capital expenditures are expected to be $304 million, or six percent, of capital expenditures in 2010. Predictions beyond 2010 can only be broad-based estimates, which have varied, and will continue to vary, due to the ongoing evolution of specific regulatory requirements, the possible imposition of more stringent requirements and the availability of new technologies, among other matters. Based on currently identified projects, we anticipate that environmental capital expenditures will be approximately $331 million in 2011; however, actual expenditures may vary as the number and scope of environmental projects are revised as a result of improved technology or changes in regulatory requirements and could increase if additional projects are identified or additional requirements are imposed.

Of particular significance to our refining operations are EPA regulations that require reduced sulfur levels in diesel fuel for off-road use. We have spent approximately $175 million between 2006 and 2009 on refinery investments to produce ultra-low sulfur diesel fuel for off-road use, in compliance with EPA regulations.

Further, we estimate that we may spend approximately $1 billion over a six-year period beginning in 2008 to comply with MSAT II regulations relating to benzene content in refined products. We have not finalized our strategy or cost estimates to comply with these requirements. Our actual MSAT II expenditures have totaled $283 million through December 31, 2009 and we expect to spend $325 million on MSAT II in 2010. The cost estimates are forward-looking statements and are subject to change as further work is completed in 2010.

For more information on environmental regulations that impact us, or could impact us, see Item 1. Business – Environmental Matters, Item 3. Legal Proceedings and Item 1A. Risk Factors.

Critical Accounting Estimates

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

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

Estimated Net Proved Reserves

We use the successful efforts method of accounting for our oil and gas producing activities. The successful efforts method inherently relies on the estimation of proved liquid hydrocarbon, natural gas and synthetic crude oil reserves, both developed and undeveloped. The existence and the estimated amount of proved reserves affect, among other things, whether certain costs are capitalized or expensed, the amount and timing of costs depreciated, depleted or amortized into net income and the presentation of supplemental information on oil and gas producing activities. Both the expected future cash flows to be generated by oil and gas producing properties used in testing such properties for impairment and the expected future taxable income available to realize deferred tax assets also rely, in part, on estimates of net recoverable quantities of reserves.

Proved reserves are the those quantities of oil and gas, which, by analysis of geoscience data, can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs, and under existing economic conditions, operating methods, and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that a renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. Estimates of proved reserves may change, either positively or negatively, as additional information becomes available and as contractual, operational, economic and political conditions change. Beginning December 31, 2009, reserve estimates are based upon an average of prices in the prior 12-month period, using the closing prices on the first day of each month. In previous periods, reserve estimates were based upon prices at December 31. Neither of these prices should be expected to reflect future market conditions. During 2009, net revisions of previous estimates increased total proved reserves by 596 mmboe (50 percent of the beginning of the year reserve estimate), with 603 mmboe of the increase related to the presentation of reserves related to oil sand mining as synthetic crude oil effective December 31, 2009 under the SEC's revised regulations.

The estimation of net recoverable quantities of liquid hydrocarbons, natural gas and synthetic crude oil is a highly technical process, which is based upon several underlying assumptions that are subject to change. For a discussion of our reserve estimation process, including the use of third-party audits, see Item 1. Business.

Depreciation and depletion of liquid hydrocarbon, natural gas and synthetic crude oil producing (including oil sands mining and upgrading assets) properties is determined by the units-of-production method and could change with revisions to estimated proved developed reserves. The change in the depreciation and depletion rate over the past three years due to revisions of previous reserve estimates has not been significant to either our E&P or our OSM segments. For our E&P segment, on average, a five percent increase in the amount of liquid hydrocarbon and natural gas reserves would lower the depreciation and depletion rate by approximately $0.53 per barrel, which would increase pretax income by approximately $78 million annually, based on 2009 production. Conversely, on average, a five percent decrease in the amount of liquid hydrocarbon and natural gas reserves would increase the depreciation and depletion rate by approximately $0.58 per barrel and would result in a decrease in pretax income of approximately $86 million annually, based on 2009 production. For our OSM segment, on average, a five percent increase in estimated synthetic crude oil reserves would lower the depreciation and depletion rate by approximately $0.66 per barrel and would result in an increase in pretax income of approximately $8 million annually, based on 2009 production. On average, a five percent decrease in estimated synthetic crude oil reserves would increase the depreciation and depletion rate by approximately $0.36 per barrel and would result in a decrease in pretax income of approximately $4 million annually, based on 2009 production.

Fair Value Estimates

Effective January 1, 2008 and 2009, we adopted the new accounting standards for assets and liabilities recognized or disclosed at fair value in the consolidated financial statements on a recurring and those recognized and disclosed on a nonrecurring basis. The standards define fair value, establish a framework for measuring fair value and expand disclosures about fair value measurements. The standards do not require us to make any new fair value measurements, but rather establish a fair value hierarchy that prioritizes the inputs to the valuation techniques used to measure fair value. Level 1 inputs are given the highest priority in the fair value hierarchy, as they represent observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date, while Level 3 inputs are given the lowest priority, as they represent unobservable inputs that are not corroborated by market data. Valuation techniques that maximize the use of observable inputs are favored. See Item 8. Financial Statements and Supplementary Data—Note 16 to the consolidated financial statements for disclosures regarding our fair value measurements.

Significant uses of fair value measurements include:

- assessment of impairment of long-lived assets,
- assessment of impairment of goodwill,
- allocation of the purchase price paid to acquire businesses to the assets acquired and liabilities assumed in those acquisitions, and
- recorded value of derivative instruments.

Impairment Assessments of Long-Lived Assets and Goodwill

Fair value calculated for the purpose of testing for impairment of our long-lived assets and goodwill is estimated using the expected present value of future cash flows method and comparative market prices when appropriate. Significant judgment is involved in performing these fair value estimates since the results are based on forecasted assumptions. Significant assumptions include:

- *Future liquid hydrocarbon, natural gas and synthetic crude oil prices.* Our estimates of future prices are based on our analysis of market supply and demand and consideration of market price indicators. Although these commodity prices may experience extreme volatility in any given year, we believe long-term industry prices are driven by global market supply and demand. To estimate supply, we consider numerous factors, including the world-wide resource base, depletion rates, and OPEC production policies. We believe demand is largely driven by global economic factors, such as population and income growth, governmental policies, and vehicle stocks. Such price estimates are consistent with those used in our planning and capital investment reviews. There has been significant volatility in the liquid hydrocarbon, natural gas and synthetic crude oil prices and estimates of such price curves are inherently imprecise.
- *Estimated recoverable quantities of liquid hydrocarbons, natural gas and synthetic crude oil.* This is based on a combination of proved and weighted probable and possible reserves such that the combined volumes represent the mean (average) expectation. These estimates are based on work performed by our engineers and that of outside consultants. Because of their very nature, probable and possible reserves are less precise than those of proved reserves. We evaluate our probable and possible reserves using drilling results, reservoir performance, seismic interpretation and future plans to develop acreage. Reserves are adjusted as new information becomes available.
- *Expected timing of production.* Production forecasts are based on a combination of proved and weighted probable and possible reserves based on engineering studies. The actual timing of the production could be different than the projection. Cash flows realized later in the projection period are less valuable than those realized earlier due to the time value of money.
- *Future margins on refined products produced and sold.* Our estimates of future product margins are based on our analysis of various supply and demand factors, which include, among other things, industry-wide capacity, our planned utilization rate, end-user demand, capital expenditures, and economic conditions. Such estimates are consistent with those used in our planning and capital investment reviews.
- *Discount rate commensurate with the risks involved.* We apply a discount rate to our cash flows based on a variety of factors, including market and economic conditions, operational risk, regulatory risk and political risk. This discount rate is also compared to recent observable market transactions, if possible. A higher discount rate decreases the net present value of cash flows.
- *Future capital requirements.* These are based on authorized spending and internal forecasts.

We base our fair value estimates on projected financial information which we believe to be reasonable. However, actual results may differ from these projections.

The need to test for impairment can be based on several indicators, including a significant reduction in prices of liquid hydrocarbons, natural gas or synthetic crude oil, unfavorable adjustments to reserves, significant changes in the expected timing of production, significant reduction in refining margins, other changes to contracts or changes in the regulatory environment in which the property is located.

Long-lived assets used in operations are assessed for impairment whenever changes in facts and circumstances indicate that the carrying value of the assets may not be recoverable. For purposes of impairment evaluation, long-lived assets must be grouped at the lowest level for which independent cash flows can be identified, which generally is field-by-field for E&P assets, project level for oil sands mining assets, refinery and associated distribution system level or pipeline system level for refining and transportation assets, or site level for retail stores. If the sum of the undiscounted estimated pretax cash flows is less than the carrying value of an asset group, the carrying value is written down to the estimated fair value.

Unlike long-lived assets, goodwill must be tested for impairment at least annually, or between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. Goodwill is tested for impairment at the reporting unit level.

An estimate as to the sensitivity to earnings resulting from impairment calculations is not practicable, given the numerous assumptions (e.g. reserves, pricing and discount rates) that can materially affect our estimates. That is, unfavorable adjustments to some of the above listed assumptions may be offset by favorable adjustments in other assumptions.

Acquisitions

Under the purchase method of accounting for business combinations, the purchase price paid to acquire a business is allocated to its assets and liabilities based on the estimated fair values of the assets acquired and liabilities assumed as of the date of acquisition. The excess of the purchase price over the fair value of the net tangible and identifiable intangible assets acquired is recorded as goodwill. A significant amount of judgment is involved in estimating the individual fair values involving property, plant and equipment and identifiable intangible assets. We use all available information to make these fair value determinations and, for certain acquisitions, engage third-party consultants for assistance.

The fair values used to allocate the purchase price of an acquisition are often estimated using the expected present value of future cash flows method, which requires us to project related future cash inflows and outflows and apply an appropriate discount rate. The estimates used in determining fair values are based on assumptions believed to be reasonable but which are inherently uncertain. Accordingly, actual results may differ from the projected results used to determine fair value.

Derivatives

We record all derivative instruments at fair value. A large volume of our commodity derivatives are exchange-traded and require few assumptions in arriving at fair value.

In our E&P segment, we had two long-term contracts for the sale of natural gas in the United Kingdom that were accounted for as derivative instruments. These contracts, which expired in September 2009, were entered into in the early 1990s in support of our investments in the East Brae field and the SAGE pipeline. The contract prices reset annually in October and were indexed to a basket of costs of living and energy commodity indices for the previous twelve months. Consequently, the prices under these contracts did not track forward natural gas prices. The fair value of these contracts was determined by applying the difference between the contract price and the U.K. forward natural gas strip price to the expected sales volumes under these contracts for the shorter of the remaining contract terms or 18 months. Adjustments to the fair value of these contracts were recorded as non-cash charges or credits to income from operations.

Our OSM segment held crude oil options which expired in December 2009. These options were designed to protect against price decreases on portions of synthetic crude oil sales and their fair value was measured using a Black-Scholes option pricing model that used prices from the active commodity market and a market volatility calculated by a third-party service.

Additional information about derivatives and their valuation may be found in Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Expected Future Taxable Income

We must estimate our expected future taxable income to assess the realizability of our deferred income tax assets.

Numerous assumptions are inherent in the estimation of future taxable income, including assumptions about matters that are dependent on future events, such as future operating conditions (particularly as related to prevailing liquid hydrocarbon, natural gas and synthetic crude oil prices) and future financial conditions. The estimates and assumptions used in determining future taxable income are consistent with those used in our internal budgets, forecasts and strategic plans.

In determining our overall estimated future taxable income for purposes of assessing the need for additional valuation allowances, we consider proved and weighted probable and possible reserves related to our existing producing properties, as well as estimated quantities of liquid hydrocarbon, natural gas and synthetic crude oil related to undeveloped discoveries if, in our judgment, it is likely that development plans will be approved in the foreseeable future. In assessing the releasing of an existing valuation allowance, we consider the preponderance of evidence concerning the realization of the impaired deferred tax asset.

Additionally, we must consider any prudent and feasible tax planning strategies that might minimize the amount of deferred tax liabilities recognized or the amount of any valuation allowance recognized against deferred tax assets, if we can implement these strategies and if we expect to implement these strategies in the event the forecasted conditions actually occurred. The principal tax planning strategy available to us relates to the permanent reinvestment of the earnings of our foreign subsidiaries. Assumptions related to the permanent reinvestment of the earnings of our foreign subsidiaries are reconsidered quarterly to give effect to changes in our portfolio of producing properties and in our tax profile.

Pension and Other Postretirement Benefit Obligations

Accounting for pension and other postretirement benefit obligations involves numerous assumptions, the most significant of which relate to the following:

- the discount rate for measuring the present value of future plan obligations;
- the expected long-term return on plan assets;
- the rate of future increases in compensation levels; and
- health care cost projections.

We develop our demographics and utilize the work of third-party actuaries to assist in the measurement of these obligations. We have selected different discount rates for our funded U.S. pension plans and our unfunded U.S. retiree health care plan due to the different projected liability durations of 8 years and 12 years. The selected rates are compared to various similar bond indexes for reasonableness. In determining the assumed discount rates, our methods include a review of market yields on high-quality corporate debt and use of our third-party actuary's discount rate modeling tool. This tool applies a yield curve to the projected benefit plan cash flows using a hypothetical Aa yield curve. The yield curve represents a series of annualized individual discount rates from 1.5 to 30 years. The bonds used are rated Aa or higher by a recognized rating agency and only non-callable bonds are included. Each issue is required to have at least $150 million par value outstanding. The top quartile bonds are selected within each maturity group to construct the yield curve.

Of the assumptions used to measure the December 31, 2009 obligations and estimated 2010 net periodic benefit cost, the discount rate has the most significant effect on the periodic benefit cost reported for the plans. A 0.25 percent decrease in the discount rates of 5.50 percent for our U.S. pension plans and 5.95 percent for our other U.S. postretirement benefit plans would increase pension obligations and other postretirement benefit plan obligations by $129 million and $21 million and would increase defined benefit pension expense and other postretirement benefit plan expense by $13 million and $2 million.

The asset rate of return assumption considers the asset mix of the plans (currently targeted at approximately 75 percent equity securities and 25 percent debt securities for the U.S. funded pension plans and 70 percent equity securities and 30 percent debt securities for the international funded pension plans), past performance and other factors. Certain components of the asset mix are modeled with various assumptions regarding inflation, debt returns and stock yields. Our long term asset rate of return assumption is compared to those of other companies and to our historical returns for reasonableness. A 0.25 percent decrease in the asset rate of return assumption would not have a significant impact on our defined benefit pension expense.

Compensation increase assumptions are based on historical experience, anticipated future management actions and demographics of the benefit plans.

Health care cost trend assumptions are developed based on historical cost data, the near-term outlook and an assessment of likely long-term trends.

Note 22 to the consolidated financial statements includes detailed information about the assumptions used to calculate the components of our defined benefit pension and other postretirement plan expense for 2009, 2008 and 2007, as well as the obligations and accumulated other comprehensive income reported on the balance sheets as of December 31, 2009, and 2008.

Contingent Liabilities

We accrue contingent liabilities for environmental remediation, tax deficiencies related to operating taxes, product liability claims and litigation claims when such contingencies are probable and estimable. Actual costs can differ from estimates for many reasons. For instance, settlement costs for claims and litigation can vary from estimates based on differing interpretations of laws, opinions on responsibility and assessments of the amount of damages. Similarly, liabilities for environmental remediation may vary from estimates because of changes in laws, regulations and their interpretation; additional information on the extent and nature of site contamination; and improvements in technology. Our in-house legal counsel regularly assesses these contingent liabilities. In certain circumstances, outside legal counsel is utilized.

We generally record losses related to these types of contingencies as cost of revenues or selling, general and administrative expenses in the consolidated statements of income, except for tax contingencies unrelated to income taxes, which are recorded as other taxes. For additional information on contingent liabilities, see Management's Discussion and Analysis of Environmental Matters, Litigation and Contingencies.

An estimate of the sensitivity to net income if other assumptions had been used in recording these liabilities is not practical because of the number of contingencies that must be assessed, the number of underlying assumptions and the wide range of reasonably possible outcomes, in terms of both the probability of loss and the estimates of such loss.

Accounting Standards Not Yet Adopted

Variable interest accounting standards were amended by the FASB in June 2009. The new accounting standards replace 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. The amended variable interest accounting standard 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. Application will be prospective beginning in the first quarter of 2010, and for all interim and annual periods thereafter. Earlier application is prohibited. Adoption is not expected to have a significant impact on our consolidated results of operations, financial position or cash flows.

A standard to improve disclosures about fair value measurements was issued by the FASB in January 2010. The additional disclosures required include: (1) the different classes of assets and liabilities measured at fair value, (2) the significant inputs and techniques used to measure Level 2 and Level 3 assets and liabilities for both recurring and nonrecurring fair value measurements, (3) the gross presentation of purchases, sales, issuances and settlements for the rollforward of Level 3 activity, and (4) the transfers in and out of Levels 1 and 2. The new disclosures are effective for interim and annual reporting periods beginning after December 15, 2009, except for the gross presentation of purchases, sales, issuances, and settlements for the rollforward of Level 3 activity. Those disclosures are effective for fiscal years beginning after December 15, 2010, and for interim periods thereafter.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

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

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

See Notes 16 and 17 to the consolidated financial statement for more information about the fair value measurement of our derivatives, as well as the amounts recorded in our consolidated balance sheets and statements of income for those which qualify as hedges and those not designated as hedges.

Commodity Price Risk

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

We regularly use commodity derivative instruments in the E&P segment to manage natural gas price risk during the time that the natural gas is held in storage before it is sold or on natural gas that is purchased to be marketed with our own natural gas production. We may act opportunistically to protect prices on forecasted sales of liquid hydrocarbon, natural gas or synthetic crude oil in our E&P or OSM segments. In late December 2009 and early January 2010, we saw an opportunity to protect a portion of our 2010 forecasted sales against the risk of declining prices.

Our RM&T segment primarily uses commodity derivative instruments to manage price risk on crude oil and refined product inventories. We also use derivative instruments to manage price risk related to the acquisition of foreign-sourced crude oil and ethanol blended with refined petroleum products. In addition, we may use commodity derivative instruments to manage risk on fixed price contracts for the sale of refined products. The majority of these derivatives are exchange-traded contracts for crude oil, natural gas, refined products, ethanol and natural gas measured at fair value with a market approach using the close-of-day settlement prices for the market making them a Level 1 in the fair value hierarchy.

Open Commodity Derivative Positions and Sensitivity Analysis

At December 31, 2009, we held open derivative contracts in our E&P segment to manage the price risk on natural gas held in storage or purchased to be marketed with our own natural gas production. These hedges were in amounts in line with normal levels of activity.

Beginning in December 2009 and into January 2010, we entered swaps on a portion of our forecast 2010 sales of liquid hydrocarbon, natural gas and synthetic crude oil as follows:

- 40 percent of natural gas sales from the lower 48 states of the U.S.
- 80 percent of synthetic crude oil sales in Canada, and
- 20 percent of liquid hydrocarbon sales in the U.S. and Norway.

We have not qualified these swaps for hedge accounting. As a result, we recognize in net income all changes in the fair value of derivative instruments used in those operations. The majority of these derivatives are measured at fair value with a market approach using broker quotes or third-party pricing services, which have been corroborated with data from active markets, making them a Level 2 in the fair value hierarchy described in the fair value accounting standards. The largest portion of open derivative contracts in our E&P and OSM segments are those related to 2010 forecasted sales, as listed on the table below:

	Term	Bbls per Day	Weighted Average Swap Price	Benchmark
Crude Oil				
U.S.	January - June 2010	35,000	$80.77	West Texas Intermediate
Norway	January - June 2010	30,000	$80.42	Dated Brent
Canada	January - December 2010	25,000	$82.56	West Texas Intermediate

	Term	Mmbtu per Day[a]	Weighted Average Swap Price	Benchmark
Natural Gas				
U.S. Lower 48	January - December 2010	80,000	$ 5.39	CIG Rocky Mountains[b]
U.S. Lower 48	January - December 2010	30,000	$ 5.59	NGPL Mid Continent[c]

(a) Million British thermal units
(b) Colorado Interstate Gas Co. ("CIG")
(c) Natural Gas Pipeline Co. of America ("NGPL")

In the table below are the significant open derivative contracts for our RM&T segment at December 31, 2009. These contracts enable us to effectively correlate our commodity price exposure to the relevant market indicators, thereby mitigating fixed price risk.

	Position	Bbls per Day	Weighted Average Price	Benchmark
Crude Oil				
Exchange-traded	Long[a]	61,677	$76.67	NYMEX Crude
Exchange-traded	Short[a]	(54,395)	$76.85	NYMEX Crude

	Term	Bbls per Day	Weighted Average Swap Price	Benchmark
Refined Products				
Exchange-traded	Long[b]	11,773	$ 2.00	NYEX Heating Oil and RBOB
Exchange-traded	Short[b]	(17,030)	$ 2.00	NYEX Heating Oil and RBOB

(a) 75 percent of these contracts expire in the first quarter of 2010.
(b) 90 percent of these contracts expire in the first quarter of 2010.

Sensitivity analysis of the incremental effects on income from operations ("IFO") of hypothetical 10 percent and 25 percent increases and decreases in commodity prices for open commodity derivative instruments as of December 31, 2009, is provided in the following table.

(In millions)	Incremental Change in IFO from a Hypothetical Price Increase of		Incremental Change in IFO from a Hypothetical Price Decrease of	
	10%	25%	10%	25%
E&P Segment				
Crude oil	$(67)	$(167)	$ 67	$167
Natural gas	(22)	(56)	22	56
OSM Segment				
Crude oil	$(75)	$(188)	$ 75	$188
RM&T Segment				
Crude oil	$ 24	$ 61	$(20)	$ (50)
Refined products	(12)	(37)	12	29

We remain at risk for possible changes in the market value of commodity derivative instruments; however, such risk should be mitigated by price changes in the underlying physical commodity. Effects of these offsets are not reflected in the above sensitivity analysis.

We evaluate our portfolio of commodity derivative instruments on an ongoing basis and add or revise strategies in anticipation of changes in market conditions and in risk profiles. Changes to the portfolio after December 31, 2009, would cause future IFO effects to differ from those presented above.

Interest Rate Risk

We are impacted by interest rate fluctuations which affect the fair value of certain financial instruments. We manage our exposure to interest rate movements by utilizing financial derivative instruments. The primary objective of this program is to reduce our overall cost of borrowing by managing the mix of fixed and floating interest rate debt in our portfolio. As of December 31, 2009, we had multiple interest rate swap agreements with a total notional amount of $1.35 billion at a weighted-average, LIBOR-based, floating rate of 4.37 percent. These interest rate swaps are designated as fair value hedges, which effectively results in an exchange of existing obligations to pay fixed interest rates for obligations to pay floating rates.

Sensitivity analysis of the projected incremental effect of a hypothetical 10 percent change in interest rates on financial assets and liabilities as of December 31, 2009, is provided in the following table.

(In millions)	Fair Value	Incremental Change in Fair Value
Financial assets (liabilities)[(a)]		
Receivable from United States Steel	$ 360	$ 2 [(c)]
Interest rate swap agreements	$ 5 [(b)]	$ 9 [(c)]
Long-term debt, including amounts due within one year	$(8,754)[(b)]	$(348)[(c)]

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

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

(c) For receivables from United States Steel and long-term debt, this assumes a 10 percent decrease in the weighted average yield-to-maturity of our receivables and long-term debt at December 31, 2009. For interest rate swap agreements, this assumes a 10 percent decrease in the effective swap rate at December 31, 2009.

At December 31, 2009, our portfolio of long-term debt was substantially comprised of fixed rate instruments. Therefore, the fair value of the portfolio is relatively sensitive to interest rate fluctuations. Our sensitivity to interest rate declines and corresponding increases in the fair value of our debt portfolio unfavorably affects our results of operations and cash flows only when we elect to repurchase or otherwise retire fixed-rate debt at prices above carrying value.

Foreign Currency Exchange Rate Risk

We manage our exposure to foreign currency exchange rates by utilizing forward and option contracts. The primary objective of this program is to reduce our exposure to movements in foreign currency exchange rates by locking in such rates. The following tables summarize our foreign currency derivative instruments as of December 31, 2009.

(In millions)	Settlement Period	Notional Amount	Weighted Average Forward Rate [(a)]
Foreign Currency Forwards			
Dollar (Canada)	January 2010 - February 2010	$24	1.062 [(b)]
Euro	March 2010 - June 2010	$ 3	1.278 [(c)]

(a) Rates shown are weighted average forward rates for the period.
(b) U.S. dollar to foreign currency.
(c) Foreign currency to U.S. dollar.

(In millions)	Period	Notional Amount	Weighted Average Exercise Price [(a)]
Foreign Currency Options			
Dollar (Canada)	January 2010 - September 2010	$144	1.042 [(b)]

(a) Rates shown are weighted average exercise prices for the period.
(b) U.S. dollar to foreign currency.

Sensitivity analysis of the incremental effects on IFO of hypothetical 10 percent increases and decreases in exchange rates for open foreign currency derivative instruments as of December 31, 2009, is provided in the following table:

	Incremental Change in IFO from a Hypothetical Exchange Rate	
(In millions)	Increase of 10%	Decrease of 10%
Forwards	$ (3)	$ 3
Options	(3)	9
Total	$ (6)	$ 12

Counterparty Risk

We are also exposed to financial risk in the event of nonperformance by counterparties. The creditworthiness of counterparties is reviewed and master netting agreements are used when appropriate.

Safe Harbor

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

Item 8. Financial Statements and Supplementary Data

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Management's Responsibilities for Financial Statements

To the Stockholders of Marathon Oil Corporation:

The accompanying consolidated financial statements of Marathon Oil Corporation and its consolidated subsidiaries ("Marathon") are the responsibility of management and have been prepared in conformity with accounting principles generally accepted in the United States of America. They necessarily include some amounts that are based on best judgments and estimates. The financial information displayed in other sections of this Annual Report on Form 10-K is consistent with these consolidated financial statements.

Marathon seeks to assure the objectivity and integrity of its financial records by careful selection of its managers, by organizational arrangements that provide an appropriate division of responsibility and by communications programs aimed at assuring that its policies and methods are understood throughout the organization.

The Board of Directors pursues its oversight role in the area of financial reporting and internal control over financial reporting through its Audit and Finance Committee. This Committee, composed solely of independent directors, regularly meets (jointly and separately) with the independent registered public accounting firm, management and internal auditors to monitor the proper discharge by each of their responsibilities relative to internal accounting controls and the consolidated financial statements.

/s/ Clarence P. Cazalot, Jr.	/s/ Janet F. Clark	/s/ Michael K. Stewart
President and Chief Executive Officer	*Executive Vice President and Chief Financial Officer*	*Vice President, Accounting and Controller*

Management's Report on Internal Control over Financial Reporting

To the Stockholders of Marathon Oil Corporation:

Marathon's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a – 15(f) under the Securities Exchange Act of 1934). An evaluation of the design and effectiveness of our internal control over financial reporting, based on the framework in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, was conducted under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer. Based on the results of this evaluation, Marathon's management concluded that its internal control over financial reporting was effective as of December 31, 2009.

The effectiveness of Marathon's internal control over financial reporting as of December 31, 2009 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

/s/ Clarence P. Cazalot, Jr.	/s/ Janet F. Clark
President and Chief Executive Officer	*Executive Vice President and Chief Financial Officer*

Report of Independent Registered Public Accounting Firm

To the Stockholders of Marathon Oil Corporation:

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Marathon Oil Corporation and its subsidiaries (the "Company") at December 31, 2009, and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 26, 2010

MARATHON OIL CORPORATION
Consolidated Statements of Income

(In millions, except per share data)	2009	2008	2007
Revenues and other income:			
Sales and other operating revenues (including consumer excise taxes)	$ 53,373	$ 74,875	$ 62,471
Sales to related parties	97	1,879	1,625
Income from equity method investments	298	765	545
Net gain on disposal of assets	205	423	36
Other income	166	188	74
Total revenues and other income	54,139	78,130	64,751
Costs and expenses:			
Cost of revenues (excludes items below)	40,560	59,677	49,129
Purchases from related parties	485	715	363
Consumer excise taxes	4,924	5,065	5,163
Depreciation, depletion and amortization	2,623	2,129	1,564
Goodwill impairment	-	1,412	-
Selling, general and administrative expenses	1,263	1,382	1,315
Other taxes	387	482	393
Exploration expenses	307	489	454
Total costs and expenses	50,549	71,351	58,381
Income from operations	3,590	6,779	6,370
Net interest and other financing income (costs)	(149)	(28)	33
Gain on foreign currency derivative instruments	-	-	182
Loss on early extinguishment of debt	-	-	(17)
Income from continuing operations before income taxes	3,441	6,751	6,568
Provision for income taxes	2,257	3,367	2,802
Income from continuing operations	1,184	3,384	3,766
Discontinued operations	279	144	190
Net income	$ 1,463	$ 3,528	$ 3,956
Per Share Data			
Basic:			
Income from continuing operations	$ 1.67	$ 4.77	$ 5.46
Discontinued operations	$ 0.39	$ 0.20	$ 0.27
Net income	$ 2.06	$ 4.97	$ 5.73
Diluted:			
Income from continuing operations	$ 1.67	$ 4.75	$ 5.42
Discontinued operations	$ 0.39	$ 0.20	$ 0.27
Net income	$ 2.06	$ 4.95	$ 5.69
Dividends paid	$ 0.96	$ 0.96	$ 0.92

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

MARATHON OIL CORPORATION
Consolidated Balance Sheets

(In millions, except per share data)	December 31, 2009	December 31, 2008
Assets		
Current assets:		
Cash and cash equivalents	$ 2,057	$ 1,285
Receivables, less allowance for doubtful accounts of $14 and $6	4,677	3,094
Receivables from United States Steel	22	23
Receivables from related parties	60	33
Inventories	3,622	3,507
Other current assets	199	461
Total current assets	10,637	8,403
Equity method investments	1,970	2,080
Receivables from United States Steel	324	469
Property, plant and equipment, less accumulated depreciation, depletion and amortization of $17,185 and $15,581	32,121	29,414
Goodwill	1,422	1,447
Other noncurrent assets	578	873
Total assets	$ 47,052	$ 42,686
Liabilities		
Current liabilities:		
Accounts payable	$ 6,982	$ 4,712
Payables to related parties	64	21
Payroll and benefits payable	399	400
Accrued taxes	547	1,133
Deferred income taxes	403	561
Other current liabilities	566	828
Long-term debt due within one year	96	98
Total current liabilities	9,057	7,753
Long-term debt	8,436	7,087
Deferred income taxes	4,104	3,330
Defined benefit postretirement plan obligations	2,056	1,609
Asset retirement obligations	1,099	963
Payable to United States Steel	5	4
Deferred credits and other liabilities	385	531
Total liabilities	25,142	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	(2,706)	(2,720)
Additional paid-in capital	6,738	6,696
Retained earnings	18,043	17,259
Accumulated other comprehensive loss	(934)	(593)
Total stockholders' equity	21,910	21,409
Total liabilities and stockholders' equity	$ 47,052	$ 42,686

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

MARATHON OIL CORPORATION
Consolidated Statements of Cash Flows

(In millions)	2009	2008	2007
Increase (decrease) in cash and cash equivalents			
Operating activities:			
Net income	$ 1,463	$ 3,528	$ 3,956
Adjustments to reconcile net income to net cash provided by operating activities:			
Loss on early extinguishment of debt	-	-	17
Discontinued operations	(279)	(144)	(190)
Deferred income taxes	1,072	94	(352)
Goodwill impairment	-	1,412	-
Depreciation, depletion and amortization	2,623	2,129	1,564
Pension and other postretirement benefits, net	(116)	133	33
Exploratory dry well costs and unproved property impairments	81	170	233
Net gain on disposal of assets	(205)	(423)	(36)
Equity method investments, net	42	62	(43)
Changes in the fair value of derivative instruments	(43)	(312)	206
Changes in:			
Current receivables	(1,632)	2,612	(1,329)
Inventories	(126)	(246)	(89)
Current accounts payable and accrued liabilities	2,169	(2,532)	1,677
All other operating, net	161	50	24
Net cash provided by continuing operations	5,210	6,533	5,671
Net cash provided by discontinued operations	58	219	229
Net cash provided by operating activities	5,268	6,752	5,900
Investing activities:			
Additions to property, plant and equipment	(6,231)	(6,989)	(3,757)
Acquisitions	-	-	(3,926)
Disposal of assets	865	999	137
Trusteed funds—withdrawals	16	752	280
Investments—loans and advances	(23)	(117)	(114)
Investments—repayments of loans and return of capital	94	93	59
Deconsolidation of Equatorial Guinea LNG Holdings Limited	-	-	(37)
Investing activities of discontinued operations	(84)	(127)	(88)
All other investing, net	125	(16)	(35)
Net cash used in investing activities	(5,238)	(5,405)	(7,481)
Financing activities:			
Borrowings	1,491	1,247	2,261
Debt issuance costs	(11)	(7)	(20)
Debt repayments	(81)	(1,366)	(694)
Issuance of common stock	4	9	27
Purchases of common stock	-	(402)	(822)
Excess tax benefits from stock-based compensation arrangements	-	7	30
Dividends paid	(679)	(681)	(637)
Contributions from minority shareholders of Equatorial Guinea LNG Holdings Limited	-	-	39
Net cash provided by (used in) financing activities	724	(1,193)	184
Effect of exchange rate changes on cash:			
Continuing operations	19	(44)	9
Discontinued operations	(1)	(24)	2
Net increase (decrease) in cash and cash equivalents	772	86	(1,386)
Cash and cash equivalents at beginning of period	1,285	1,199	2,585
Cash and cash equivalents at end of period	$ 2,057	$ 1,285	$ 1,199

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

MARATHON OIL CORPORATION
Consolidated Statements of Stockholders' Equity

(In millions)	Preferred Stock	Common Stock	Securities Exchangeable for Common Stock	Treasury Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
Balance as of January 1, 2007	$ -	$ 736	$ -	$ (1,638)	$ 4,784	$ 11,093	$ (368)	$ 14,607
Shares issued - acquisition	-	29	-	-	1,844	-	-	1,873
Shares issued - stock based compensation	-	-	-	99	-	-	-	99
Shares repurchased	-	-	-	(845)	-	-	-	(845)
Stock-based compensation	-	-	-	-	51	-	-	51
Net income	-	-	-	-	-	3,956	-	3,956
Other comprehensive income(loss)	-	-	-	-		-	119	119
Dividends paid	-	-	-	-	-	(637)	-	(637)
Balance as of December 31, 2007	$ -	$ 765	$ -	$ (2,384)	$ 6,679	$ 14,412	$ (249)	$ 19,223
Shares issued - stock based compensation	-	-	-	76	(63)	-	-	13
Shares exchanged	-	2	-	-	2	-	-	4
Shares repurchased	-	-	-	(412)	-	-	-	(412)
Stock-based compensation	-	-	-	-	78	-	-	78
Net income	-	-	-	-	-	3,528	-	3,528
Other comprehensive income(loss)	-	-	-	-	-	-	(344)	(344)
Dividends paid	-	-	-	-	-	(681)	-	(681)
Balance as of December 31, 2008	$ -	$ 767	$ -	$ (2,720)	$ 6,696	$ 17,259	$ (593)	$ 21,409
Shares issued - stock based compensation	-	-	-	20	(9)	-	-	11
Shares exchanged	-	2	-	-	(2)	-	-	-
Shares repurchased	-	-	-	(6)	-	-	-	(6)
Stock-based compensation	-	-	-	-	53	-	-	53
Net income	-	-	-	-	-	1,463	-	1,463
Other comprehensive income(loss)	-	-	-	-	-	-	(341)	(341)
Dividends paid	-	-	-	-	-	(679)	-	(679)
Balance as of December 31, 2009	$ -	$ 769	$ -	$ (2,706)	$ 6,738	$ 18,043	$ (934)	$ 21,910

(Shares in millions)	Preferred Stock	Common Stock	Securities Exchangeable for Common Stock	Treasury Stock
Balance as of January 1, 2007	-	736	-	(40)
Shares issued - acquisition	5	29	5	-
Shares issued - stock based compensation	-	-	-	2
Shares repurchased	-	-	-	(17)
Balance as of December 31, 2007	5	765	5	(55)
Shares issued - stock based compensation	-	-	-	2
Shares exchanged	(2)	2	(2)	-
Shares repurchased	-	-	-	(8)
Balance as of December 31, 2008	3	767	3	(61)
Shares issued - stock based compensation	-	-	-	-
Shares exchanged	(2)	2	(2)	-
Balance as of December 31, 2009	1	769	1	(61)

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

MARATHON OIL CORPORATION
Consolidated Statements of Comprehensive Income

(In millions)	2009	2008	2007
Net income	$ 1,463	$ 3,528	$ 3,956
Other comprehensive income (loss)			
Post-retirement and post-employment plans			
Change in actuarial gain (loss)	(564)	(397)	194
Income tax benefit (provision) on post-retirement and post-employment plans	208	147	(87)
Post-retirement and post-employment plans, net of tax	(356)	(250)	107
Derivative hedges			
Net unrecognized gain (loss)	24	(91)	13
Income tax benefit (provision) on derivatives	(12)	24	(4)
Derivative hedges, net of tax	12	(67)	9
Foreign currency translation and other			
Unrealized gain (loss)	4	(43)	5
Income tax benefit (provision) on foreign currency translation and other	(1)	16	(2)
Foreign currency translation and other, net of tax	3	(27)	3
Other comprehensive income (loss)	(341)	(344)	119
Comprehensive income	$ 1,122	$ 3,184	$ 4,075

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

1. Summary of Principal Accounting Policies

We are engaged in worldwide exploration, production and marketing of liquid hydrocarbons and natural gas; oil sands mining and bitumen upgrading in Canada; domestic refining, marketing and transportation of crude oil and petroleum products; and worldwide marketing and transportation of products manufactured from natural gas, such as liquefied natural gas ("LNG") and methanol.

Principles applied in consolidation – These consolidated financial statements include the accounts of our majority-owned, controlled subsidiaries and variable interest entities for which we are the primary beneficiary.

Investments in entities over which we have significant influence, but not control, are accounted for using the equity method of accounting and are carried at our share of net assets plus loans and advances. This includes entities in which we hold majority ownership but the minority shareholders have substantive participating rights in the investee. Income from equity method investments represents our proportionate share of net income generated by the equity method investees. Differences in the basis of the investments and the separate net asset value of the investees, if any, are amortized into net income over the remaining useful lives of the underlying assets, except for the excess related to goodwill.

Equity method investments are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value has occurred, if the loss is deemed to be other than temporary. When the loss is deemed to be other than temporary, the carrying value of the equity method investment is written down to fair value, and the amount of the write-down is included in net income.

Investments in unincorporated joint ventures and undivided interests in certain operating assets are consolidated on a pro rata basis.

Reclassifications – We have revised prior years amounts of capital expenditures in the consolidated statement of cash flows. The presentation within the consolidated statement of cash flows for additions to property, plant and equipment reflects capital expenditures on a cash basis. The following reflects the reclassifications made:

(in millions)	2008	2007
Capital expenditures, previously reported	$ (7,146)	$ (4,466)
Reclassification of capital accruals	30	621
Additions to property, plant and equipment, including discontinued operations	$ (7,116)	$ (3,845)

The corresponding offsets to the amounts above have been reflected within cash provided by operating activities through change in current accounts payable and accrued liabilities.

(in millions)	2008	2007
Cash flow from operations, previously reported	$ 6,782	$ 6,521
Reclassification of capital accruals	(30)	(621)
Cash flow from operations	$ 6,752	$ 5,900

Use of estimates – The preparation of financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods.

Foreign currency transactions – The U.S. dollar is the functional currency of our foreign operating subsidiaries. Foreign currency transaction gains and losses are included in net income.

Revenue recognition – Revenues are recognized when products are shipped or services are provided to customers, title is transferred, the sales price is fixed or determinable and collectability is reasonably assured. Costs associated with revenues are recorded in cost of revenues.

In the continental United States, production volumes of liquid hydrocarbons and natural gas are sold immediately and transported via pipeline. In Alaska and international locations, liquid hydrocarbon and natural gas production volumes may be stored as inventory and sold at a later time. In Canada, mined bitumen is first processed through the Scotford upgrader and then sold as synthetic crude oil. Both bitumen and synthetic crude oil may be stored as inventory.

We follow the sales method of accounting for crude oil and natural gas production imbalances and would recognize a liability if the existing proved reserves were not adequate to cover an imbalance. Imbalances have not been significant in the periods presented.

Rebates from vendors are recognized as a reduction of cost of revenues when the initiating transaction occurs. Incentives that are derived from contractual provisions are accrued based on past experience and recognized in cost of revenues.

Consumer excise taxes – We are required by various governmental authorities, including countries, states and municipalities, to collect and remit taxes on certain consumer products. Such taxes are presented on a gross basis in revenues and costs and expenses in the consolidated statements of income.

Cash and cash equivalents – Cash and cash equivalents include cash on hand and on deposit and investments in highly liquid debt instruments with original maturities of three months or less.

Accounts receivable and allowance for doubtful accounts – Our receivables primarily consist of customer accounts receivable, including proprietary credit card receivables. The allowance for doubtful accounts is the best estimate of the amount of probable credit losses in our proprietary credit card receivables. We determine the allowance based on historical write-off experience and the volume of proprietary credit card sales. We review the allowance quarterly and past-due balances over 180 days are reviewed individually for collectability. All other customer receivables are recorded at the invoiced amounts and generally do not bear interest. Account balances for these customer receivables are charged directly to bad debt expense when it becomes probable the receivable will not be collected.

Inventories – Inventories are carried at the lower of cost or market value. Cost of inventories is determined primarily under the last-in, first-out ("LIFO") method.

We may enter into a contract to sell a particular quantity and quality of crude oil or refined product at a specified location and date to a particular counterparty, and simultaneously agree to buy a particular quantity and quality of the same commodity at a specified location on the same or another specified date from the same counterparty. We account for such matching buy/sell arrangements entered into or modified as exchanges of inventory, except for those arrangements accounted for as derivative instruments.

Derivative instruments – We may use derivatives to manage a portion of our exposure to commodity price risk, interest rate risk and foreign currency exchange rate risk. We also have limited authority to use selective derivative instruments that assume market risk. All derivative instruments are recorded at fair value. Commodity derivatives are reflected on our consolidated balance sheet on a net basis by brokerage firm, as they are governed by master netting agreements. Cash flows related to derivatives used to manage commodity price risk, interest rate risk and foreign currency exchange rate risk related to operating expenditures are classified in operating activities with the underlying transactions. Cash flows related to derivatives used to manage exchange rate risk related to capital expenditures denominated in foreign currencies are classified in investing activities with the underlying transactions.

Cash flow hedges – We may use foreign currency forwards and options to manage foreign currency risk associated with anticipated transactions, primarily expenditures for capital projects denominated in certain foreign currencies, and designate them as cash flow hedges. The effective portion of 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 is recognized in net interest and financing costs as it occurs. For a discontinued cash flow hedge, 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.

We may use interest rate derivative instruments to manage the risk of interest rate changes during the period prior to anticipated borrowings and designate them as cash flow hedges. No such derivatives were outstanding at December 31, 2009.

Fair value hedges – We may use interest rate swaps to manage our exposure to interest rate risk associated with fixed interest rate debt in our portfolio and we may use commodity derivative instruments to manage the price risk on natural gas that we purchase to be marketed with our natural gas production. Changes in 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.

Derivatives not designated as hedges – Derivatives that are not designated as hedges primarily include commodity derivatives used to manage price risk on: (1) the forecast sale of crude oil, natural gas and synthetic crude oil that we produce, (2) inventories, (3) fixed price sales of refined products, (4) the acquisition of foreign-sourced crude oil, and (5) the acquisition of ethanol for blending with refined products. Changes in the fair value of derivatives not designated as hedges are recognized immediately in net income.

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.

Property, plant and equipment – We use the successful efforts method of accounting for oil and gas producing activities.

Property acquisition costs – Costs to acquire mineral interests in oil and natural gas properties, to drill and equip exploratory wells that find proved reserves and to drill and equip development wells are capitalized. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs and costs of carrying and retaining unproved properties are expensed. Costs incurred for exploratory wells that find reserves but cannot yet be classified as proved are capitalized if (1) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (2) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. The status of suspended well costs is monitored continuously and reviewed not less than quarterly.

Capitalized costs related to oil sands mining are those specifically related to the acquisition, exploration, development and construction of mining projects. Development costs to expand the capacity of existing mines are also capitalized.

Depreciation, depletion and amortization – Capitalized costs of producing oil and natural gas properties are depreciated and depleted on a units-of-production basis based on estimated proved oil and gas reserves.

Oil sands mining properties and the related bitumen upgrading facility are depreciated and depleted on a units-of-production basis.

Support equipment and other property, plant and equipment related to oil and gas producing and oil sands mining activities are depreciated on a straight-line basis over their estimated useful lives which range from 5 to 39 years.

Property, plant and equipment unrelated to oil and gas producing or oil sands mining activities is recorded at cost and depreciated on a straight-line basis over the estimated useful lives of the assets, which range from 3 to 42 years.

Impairments – We evaluate our oil and gas producing properties for impairment of value whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If the sum of the expected undiscounted future cash flows from the use of the asset and its eventual disposition is less than the carrying amount of the asset, an impairment loss is recognized based on the fair value of the asset. Oil and gas producing properties are reviewed for impairment on a field-by-field basis or, in certain instances, by logical grouping of assets if there is significant shared infrastructure. Impairment of proved properties is required when the carrying value exceeds the related undiscounted future net cash flows based on total proved and risk-adjusted probable and possible reserves. Oil and gas producing properties deemed to be impaired are written down to their fair value, as determined by discounted future net cash flows based on total proved and risk-adjusted probable and possible reserves or, if available, comparable market value. We evaluate our unproved property investment and record impairment based on time or geologic factors in addition to the use of an undiscounted future net cash flow approach. Information such as drilling results, reservoir performance, seismic interpretation or future plans to develop acreage are also considered. Unproved property investments deemed to be impaired are written down to their fair value, as determined by discounted future net cash flows. Impairment expense for unproved oil and natural gas properties is reported in exploration expenses.

Assets related to oil sands mining are reviewed for impairment whenever events or changes in circumstances indicate that the carrying value may not be recoverable from estimated undiscounted future net cash flows based on total bitumen reserves. Assets deemed to be impaired are written down to their fair value, as determined by discounted future net cash flows.

Refining, marketing and transportation assets are reviewed for impairment whenever events or changes in the circumstances indicate that the carrying amount of an asset may not be recoverable. If the sum of the expected undiscounted future cash flows from the use of the asset and its eventual disposition is less than the carrying amount of the asset, an impairment loss is recognized based on the fair value of the asset.

Dispositions – When property, plant and equipment depreciated on an individual basis are sold or otherwise disposed of, any gains or losses are reported in net income. Gains on the disposal of property, plant and equipment are recognized when earned, which is generally at the time of closing. If a loss on disposal is expected, such losses are recognized when the assets are classified as held for sale. Proceeds from the disposal of property, plant and equipment depreciated on a group basis are credited to accumulated depreciation, depletion and amortization with no immediate effect on net income.

Goodwill – Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the acquisition of a business. Such goodwill is not amortized, but rather is tested for impairment annually and when events or changes in circumstances indicate that the fair value of a reporting unit with goodwill has been reduced below carrying value. The impairment test requires allocating goodwill and other assets and liabilities to reporting units. The fair value of each reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, including goodwill, then the recorded goodwill is impaired to its implied fair value with a charge to operating expense.

Major maintenance activities – Costs are incurred for planned major maintenance. These types of costs include contractor repair services, materials and supplies, equipment rentals and our labor costs. Such costs are expensed in the period incurred.

Environmental costs – Environmental expenditures are capitalized if the costs mitigate or prevent future contamination or if the costs improve environmental safety or efficiency of the existing assets. We provide for remediation costs and penalties when the responsibility to remediate is probable and the amount of associated costs can be reasonably estimated. The timing of remediation accruals coincides with completion of a feasibility study or the commitment to a formal plan of action. Remediation liabilities are accrued based on estimates of known environmental exposure and are discounted when the estimated amounts are reasonably fixed and determinable. If recoveries of remediation costs from third parties are probable, a receivable is recorded and is discounted when the estimated amount is reasonably fixed and determinable.

Asset retirement obligations – The fair value of asset retirement obligations is recognized in the period in which the obligations are incurred if a reasonable estimate of fair value can be made. Our asset retirement obligations primarily relate to the abandonment of oil and gas producing facilities. Asset retirement obligations for such facilities include costs to dismantle and relocate or dispose of production platforms, gathering systems, wells and related structures and restoration costs of land and seabed, including those leased. Estimates of these costs are developed for each property based on the type of production structure, depth of water, reservoir characteristics, depth of the reservoir, market demand for equipment, currently available procedures and consultations with construction and engineering professionals. Asset retirement obligations have not been recognized for certain of our international oil and gas producing facilities as we currently do not have a legal obligation associated with the retirement of those facilities.

To a lesser extent, asset retirement obligations related to dismantlement, site restoration of oil sands mining facilities and, conditional asset retirement obligations for removal and disposal of fire-retardant material from certain refining facilities have also been recognized. The amounts recorded for such obligations are based on the most probable current cost projections. Asset retirement obligations have not been recognized for the removal of materials and equipment from or the closure of certain refinery, pipeline, marketing and bitumen upgrading assets because the fair value cannot be reasonably estimated since the settlement dates of the obligations are indeterminate.

Current inflation rates and credit-adjusted-risk-free interest rates are used to estimate the fair value of asset retirement obligations. Depreciation of capitalized asset retirement costs and accretion of asset retirement obligations are recorded over time. Depreciation is generally determined on a units-of-production basis for oil and gas production and oil sands mining facilities and on a straight-line basis for refining facilities, while accretion escalates over the lives of the assets.

Deferred taxes – Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases as reported in our filings with the respective taxing authorities. Deferred tax assets are recorded when it is more likely than not that they will be realized. The realization of deferred tax assets is assessed periodically based on several interrelated factors. These factors include our expectation to generate sufficient future taxable income including future foreign source income, tax credits, operating loss carryforwards and management's intent regarding the permanent reinvestment of the income from certain foreign subsidiaries.

Stock-based compensation arrangements – The fair value of stock options, stock options with tandem stock appreciation rights ("SARs") and stock-settled SARs ("stock option awards") is estimated on the date of grant using the Black-Scholes option pricing model. The model employs various assumptions, based on management's best estimates at the time of grant, which impact the calculation of fair value and ultimately, the amount of expense that is recognized over the life of the stock option award. Of the required assumptions, the expected life of the stock option award and the expected volatility of our stock price have the most significant impact on the fair value calculation. We have utilized historical data and analyzed current information which reasonably support these assumptions.

The fair value of our restricted stock awards and common stock units is determined based on the fair market value of Marathon common stock on the date of grant.

Our stock-based compensation expense is recognized based on management's best estimate of the awards that are expected to vest, using the straight-line attribution method for all service-based awards with a graded vesting feature. If actual forfeiture results are different than expected, adjustments to recognized compensation expense may be required in future periods. Unearned stock-based compensation is charged to stockholders' equity when restricted stock awards are granted. Compensation expense is recognized over the vesting period and is adjusted if conditions of the restricted stock award are not met. Options with tandem SARs are classified as a liability and are remeasured at fair value each reporting period until settlement.

2. Accounting Standards

Recently Adopted

Oil and Gas Reserve Estimation and Disclosure standards were issued by the Financial Accounting Standards Board ("FASB") in January 2010, which aligns the FASB's reporting requirements with the below requirements of the Securities and Exchange Commission ("SEC"). The FASB also addresses the impact of changes in the SEC's rules and definitions on accounting for oil and gas producing activities. Similar to the SEC requirements, the FASB requirements were effective for periods ending on or after December 31, 2009. Initial adoption did not have an impact on our consolidated results of operations, financial position or cash flows; however, there will be an impact on the amount of depreciation, depletion and amortization expense recognized in future periods. We expect this effect as compared to prior periods will not be significant. The required disclosures are presented in Supplementary Information on Oil and Gas Producing Activities (Unaudited).

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.
- Permit companies to disclose their probable and possible reserves on a voluntary basis.
- 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.
- 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 are required.
- Require separate disclosure of reserves in foreign countries if they represent 15 percent or more of total proved reserves, based on barrels of oil equivalents.

As with the FASB standard described above, adoption did not have an impact on our consolidated results of operations, financial position or cash flows. The additional disclosures required by the SEC can be found in Item 1. Business – Reserves.

Measuring liabilities at fair value, a FASB accounting standards update, was issued in August 2009. This update provides clarification for circumstances in which a quoted price in an active market for an identical liability is not available. In such circumstances, an entity is required to measure fair value using (1) the quoted price of the identical liability when traded as an asset, or (2) quoted prices for similar liabilities or similar liabilities when traded as assets, or (3) another valuation technique consistent with the fair value measurement principles such as an income approach or a market approach. The new update for measuring liabilities at fair value was effective for the third quarter of 2009. Adoption did not have an impact on our consolidated results of operations, financial position or cash flows.

Subsequent events accounting standards were issued in May 2009 by the FASB, establishing the of accounting and disclosure standards for events that occur after the balance sheet date but before financial statements are issued or available to be issued. This codifies into the accounting standards guidance that existed in the auditing standards and should not significantly change the subsequent events that we report. We began applying these standards prospectively in the second quarter of 2009. The disclosures required appear in Note 1.

Interim disclosures about fair value of financial instruments were expanded by the FASB in April 2009. Disclosures about fair value of financial instruments are now required in interim reporting periods for publicly traded companies. This change was effective for the second quarter of 2009 and did 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 16.

Guidance for determining fair value when the volume and level of activity for the asset or liability have significantly decreased and guidance on identifying circumstances that indicate a transaction is not orderly was also issued in April 2009 by the FASB. It was effective for the second quarter of 2009 and did 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.

Accounting considerations for equity method investments were ratified by the FASB in November 2008, which address the initial measurement, decreases in value and changes in the level of ownership of the equity method investment. These were 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 these were applied prospectively, adoption did not have a significant impact on our consolidated results of operations, financial position or cash flows.

Guidance for determining whether instruments granted in share-based payment transactions are participating securities was issued by the FASB in June 2008. It 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. It was effective January 1, 2009 and all prior-period EPS data (including any amounts related to interim periods, summaries of earnings and selected financial data) were adjusted retrospectively to conform to its provisions. While our restricted stock awards meet this definition of participating securities, this application did not have a significant impact on our reported EPS.

Guidance for determining the useful life of intangible assets was issued in April 2008 by the FASB. This guidance amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. The intent 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. It was effective on January 1, 2009 and was 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 is applied prospectively, adoption did not have a significant impact on our consolidated results of operations, financial position or cash flows.

Disclosures requirements for derivative instruments and hedging activities were expanded by the FASB in March 2008 to provide information regarding (1) how and why an entity uses derivative instruments, (2) how derivative instruments and related hedged items are accounted for and (3) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. Requirements include 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. The amendments were effective January 1, 2009 and encouraged, but did not require, disclosures for earlier periods presented for comparative purposes at initial adoption. The required disclosures appear in Note 17.

Accounting for business combinations was revised by the FASB in December 2007. This significantly changes the accounting for business combinations. 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 definition of a business is expanded and is expected to be applicable to more transactions. In addition, there are changes in 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 guidance for accounting for assets acquired and liabilities assumed in a business combination that arise from contingencies. Both the December 2007 revision and the April 2009 guidance were effective on January 1, 2009 for all new business combinations. Because we had no business combinations in progress at January 1, 2009, adoption did not have a significant impact on our consolidated results of operations, financial position or cash flows.

Accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary were issued in December 2007 by the FASB. Specifically, the standards clarified 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. It also 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, a parent must 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 implementation questions regarding the new accounting standards for noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. Both the new accounting standards and the implementation questions were effective January 1, 2009 and 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 did not have a significant impact on our consolidated results of operations, financial position or cash flows.

Accounting and reporting standards for fair value measurements were issued in September 2006 by the FASB. The standards define fair value, establish a framework for measuring fair value in generally accepted accounting principles and expand disclosures about fair value measurements. The standards do not require any new fair value measurements but may require some entities to change their measurement practices. We adopted these standards effective January 1, 2008 with respect to financial assets and liabilities and effective January 1, 2009 with respect to nonfinancial assets and liabilities. Adoption did not have a significant impact on our consolidated results of operations, financial position or cash flows.

Application guidance to address fair value measurements for purposes of lease classification or measurement in accounting for leases was issued in February 2008 by the FASB. This guidance removes certain leasing transactions from the scope of fair value accounting and adoption did not have a significant impact on our consolidated results of operations, financial position or cash flows.

Guidance for determining the fair value of a financial asset when the market for that asset is not active was issued by the FASB in October 2008. It clarifies the application of fair value measurements 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. This guidance 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 this new guidance did not cause us to change our valuation techniques for assets and liabilities.

The fair value disclosures are presented in Note 16.

An employer's disclosures about plan assets of defined benefit pension or other postretirement plans were expanded in December 2008 by the FASB. Additional disclosures about investment policies and strategies, the reporting of fair value by asset category and other information about fair value measurements is required. This was effective January 1, 2009 and early application is permitted. Upon initial application, these new disclosures are not required for earlier periods that are presented for comparative purposes. These additional disclosures are presented in Note 22.

Not Yet Adopted

Variable interest accounting standards were amended by the FASB in June 2009. The new accounting standards replace 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. The amended variable interest accounting standard 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. Application will be prospective beginning in the first quarter of 2010, and for all interim and annual periods thereafter. Earlier application is prohibited. Adoption is not expected to have a significant impact on our consolidated results of operations, financial position or cash flows.

A standard to improve disclosures about fair value measurements was issued by the FASB in January 2010. The additional disclosures required include: (1) the different classes of assets and liabilities measured at fair value, (2) the significant inputs and techniques used to measure Level 2 and Level 3 assets and liabilities for both recurring and nonrecurring fair value measurements, (3) the gross presentation of purchases, sales, issuances and settlements for the rollforward of Level 3 activity, and (4) the transfers in and out of Levels 1 and 2. The new disclosures are effective for interim and annual reporting periods beginning after December 15, 2009, except for the gross presentation of purchases, sales, issuances, and settlements for the rollforward of Level 3 activity. Those disclosures are effective for fiscal years beginning after December 15, 2010, and for interim periods thereafter.

3. Information about United States Steel

The USX Separation – Prior to December 31, 2001, Marathon had two outstanding classes of common stock: USX—Marathon Group common stock, which was intended to reflect the performance of our energy business, and USX—U.S. Steel Group common stock ("Steel Stock"), which was intended to reflect the performance of our steel business. On December 31, 2001, in a tax-free distribution to holders of Steel Stock, we exchanged the common stock of United States Steel for all outstanding shares of Steel Stock on a one-for-one basis (the "USX Separation"). In connection with the USX Separation, Marathon and United States Steel entered into a number of agreements, including:

Financial Matters Agreement – Marathon and United States Steel entered into a Financial Matters Agreement that provides for United States Steel's assumption of certain industrial revenue bonds and certain other financial obligations of Marathon. The Financial Matters Agreement also provides that, on or before the tenth anniversary of the USX Separation, United States Steel will provide for our discharge from any remaining liability under any of the assumed industrial revenue bonds.

Under the Financial Matters Agreement, United States Steel has all of the existing contractual rights under the leases assumed, including all rights related to purchase options, prepayments or the grant or release of security interests. However, United States Steel has no right to increase amounts due under or lengthen the term of any of the assumed leases, other than extensions set forth in the terms of any of the assumed leases.

United States Steel was the sole general partner of Clairton 1314B Partnership, L.P., which owned certain cokemaking facilities at United States Steel Clairton Works. We guaranteed to the limited partners all obligations of United States Steel under the partnership documents ("the Clairton 1314B Guarantee"). The Financial Matters Agreement requires United States Steel to use commercially reasonable efforts to have Marathon released from its obligations under this guarantee. The Clairton 1314B Partnership was terminated on October 31, 2008. We were not released from our obligations under the Clairton 1314B Guarantee upon termination of the partnership. As a result, we continue to guarantee the United States Steel indemnification of the former limited partners for certain income tax exposures.

The Financial Matters Agreement requires us to use commercially reasonable efforts to assure compliance with all covenants and other obligations to avoid the occurrence of a default or the acceleration of payments on the assumed obligations.

United States Steel's obligations to Marathon under the Financial Matters Agreement are general unsecured obligations that rank equal to United States Steel's accounts payable and other general unsecured obligations. The Financial Matters Agreement does not contain any financial covenants and United States Steel is free to incur additional debt, grant mortgages on or security interests in its property and sell or transfer assets without our consent.

4. Variable Interest Entities

Equatorial Guinea LNG Holdings Limited ("EGHoldings"), in which we hold a 60 percent interest, was formed for the purpose of constructing and operating an LNG production facility. During facility construction, EGHoldings was a variable interest entity ("VIE") that was consolidated because we were its primary beneficiary. Once the LNG production facility commenced its primary operations and began to generate revenue in May 2007, EGHoldings was no longer a VIE. Effective May 1, 2007, we no longer consolidated EGHoldings, despite the fact that we hold majority ownership, because the minority shareholders have rights limiting our ability to exercise control over the entity. We account for our investment in EGHoldings, using the equity method of accounting, at our share of net assets plus loans and advances, if any. Our investment is included in the equity method investments line of our consolidated balance sheet (see Note 13 to the consolidated financial statements).

The owners of the Athabasca Oil Sands Project ("AOSP"), in which we own 20 percent, contracted with a wholly owned subsidiary of a publicly traded Canadian limited partnership ("Corridor Pipeline") to provide materials transportation capabilities among the Muskeg River mine, the Scotford Upgrader and markets in Edmonton. The contract, originally signed in 1999, by Marathon's predecessor, allows each owner to ship materials in accordance with its AOSP ownership. Currently, no third-party shippers use the pipeline. Under this agreement, the AOSP owners collectively are absorbing all of the operating and capital costs of the pipeline. Should shipments be suspended, by choice or due to force majeure, the AOSP owners remain responsible for the payments. This contract therefore qualifies as a variable interest contractual arrangement in a VIE. We hold a significant variable interest but are not the primary beneficiary; therefore, the Corridor Pipeline is not consolidated by Marathon. Our maximum exposure to loss as a result of our involvement with this VIE is the maximum amount we will be required to pay over the contract term, which was $928 million as of December 31, 2009. The contract expires in 2029; however, the shippers can perpetually extend its term.

5. Related Party Transactions

During 2009, 2008 and 2007 only our equity method investees were considered related parties including:

- Alba Plant LLC, in which we have a 52 percent noncontrolling interest. Alba Plant LLC processes liquefied petroleum gas.
- The Andersons Clymers Ethanol LLC, in which we have a 35 percent interest, and The Andersons Marathon Ethanol LLC, in which we have a 50 percent interest ("Ethanol investments"). These companies each own an ethanol production facility.
- Atlantic Methanol Production Company LLC ("AMPCO"), in which we have a 45 percent interest. AMPCO is engaged in methanol production activity.
- Centennial Pipeline LLC ("Centennial"), in which we have a 50 percent interest. Centennial operates a refined products pipeline and storage facility.
- EGHoldings, in which we have a 60 percent noncontrolling interest. EGHoldings processes liquefied natural gas.
- LOOP LLC, in which we have a 51 percent noncontrolling interest. LOOP LLC operates an offshore oil port.

- Pilot Travel Centers LLC ("PTC"), in which we sold our 50 percent interest in October 2008. PTC owns and operates travel centers primarily in the United States.
- Poseidon Oil Pipeline Company, LLC ("Poseidon"), in which we have a 28 percent interest. Poseidon transports crude oil.

We believe that transactions with related parties were conducted under terms comparable to those with unrelated parties. Related party sales to PTC consisted primarily of petroleum products. In the fourth quarter of 2008, we completed the sale of our 50 percent ownership interest in PTC.

Revenues from related parties were as follows:

(In millions)	2009	2008	2007
EGHoldings	$ 44	$ 39	$ 19
Centennial	34	31	27
Other equity method investees	19	20	23
PTC	-	1,789	1,556
Total	$ 97	$ 1,879	$ 1,625

Purchases from related parties were as follows:

(In millions)	2009	2008	2007
Alba Plant LLC	$ 143	$ 235	$ 131
Ethanol investments	143	188	9
Poseidon	53	154	16
Centennial	58	61	57
LOOP LLC	40	35	43
Other equity method investees	48	42	107
Total	$ 485	$ 715	$ 363

Current receivables from related parties were as follows:

	December 31,	
(In millions)	2009	2008
EGHoldings	$ 36	$ 19
Poseidon	11	1
Alba Plant LLC	10	6
AMPCO	2	5
Other equity method investees	1	2
Total	$ 60	$ 33

Payables to related parties were as follows:

	December 31,	
(In millions)	2009	2008
Poseidon	$ 20	$ 3
LOOP	17	2
Ethanol investments	9	6
Alba Plant LLC	9	5
Other equity method investees	9	5
Total	$ 64	$ 21

6. Acquisitions

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

The final purchase price for the Western acquisition was as follows:

(In millions)	
Cash[(a)]	$ 3,907
Marathon common stock and securities exchangeable for Marathon common stock[(b)]	1,910
Transaction-related costs	16
Purchase price	5,833
Fair value of debt acquired	1,063
Total consideration including debt acquired	$ 6,896

(a) Western shareholders received cash of 3,808 million Canadian dollars.

(b) Western shareholders received 29 million shares of Marathon common stock and 5 million securities exchangeable for Marathon common stock valued at $55.70 per share, which was the average common stock price over the trading days between July 26 and August 1, 2007 (the days surrounding the announcement of the transaction).

The primary reasons for the acquisition and the principal factors contributing to a purchase price resulting in goodwill are: access to the long-life AOSP of northern Alberta, Canada; the opportunity to realize a fully-integrated oil strategy, capitalizing on the ownership of this asset by aligning production from the AOSP developments, including planned expansions of the current mining operations, with our refining system; potential for expanded growth opportunities in the Athabasca region; and access to a trained workforce with expertise in bitumen production and upgrading and in synthetic crude oil marketing. The goodwill arising from the purchase price allocation was $1,508 million, of which $1,437 million was assigned to the Oil Sands Mining segment and $71 million was assigned to the E&P segment. Reductions of $25 million were made to Oil Sands Mining segment goodwill upon resolution of tax and royalty issues in 2008. None of the goodwill is deductible for tax purposes.

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

(In millions, except per share amounts)	2007
Revenues and other income	$ 65,633
Income from continuing operations	3,313
Net income	3,503
Per share data:	
Income from continuing operations basic	$ 4.80
Income from continuing operations diluted	$ 4.77
Net income basic	$ 5.08
Net income diluted	$ 5.04

7. Dispositions

During 2009, we have disposed of our exploration and production businesses in Ireland, Gabon and certain producing assets in the Permian Basin of New Mexico and Texas. At December 31, 2009, agreements were pending to dispose of certain assets under development in Angola (see discussion below). These dispositions all relate to our Exploration and Production ("E&P") segment. Our Irish and Gabonese 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.

Discontinued operations—Revenues and pretax income associated with our discontinued Irish and Gabonese operations are shown in the following table:

(In millions)	2009	2008	2007
Revenues applicable to discontinued operations	$ 188	$ 439	$ 456
Pretax income from discontinued operations	$ 80	$ 221	$ 281

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. The sale closed and we received net proceeds of $1.3 billion in February 2010. The pretax gain on the sale will be approximately $800 million. We retained a 10 percent outside-operated interest in Block 32.

Gabon disposition – In December 2009, we closed the sale of our operated fields offshore Gabon, receiving net proceeds of $269 million, after closing adjustments. A $232 million pretax gain on this disposition was reported in discontinued operations for 2009.

Permian Basin disposition – In June 2009, we closed the sale of our operated and a portion of our outside-operated Permian Basin producing assets in New Mexico and west Texas for net proceeds after closing adjustments of $293 million. A $196 million pretax gain on the sale was recorded.

Ireland dispositions – 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.

In June 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 were estimated to 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. The fair value of the proceeds was estimated to be $311 million. Fair value of anticipated sale proceeds includes (i) $100 million received at closing, (ii) $135 million minimum amount due at the earlier of first gas or December 31, 2012, and (iii) a range of zero to $165 million of contingent proceeds subject to the timing of first commercial gas. A $154 million impairment of the held for sale asset was recognized in discontinued operations in the second quarter of 2009 (see Note 16) since the fair value of the disposal group was less than the net book value. Final proceeds will range between $135 million (minimum amount) to $300 million and are due on the earlier of first commercial gas or December 31, 2012. The fair value of the expected final proceeds was recorded as an asset at closing. As a result of new public information in the fourth quarter of 2009, a writeoff was recorded on the contingent portion of the proceeds (see Note 10).

Existing guarantees of our subsidiaries' performance issued to Irish government entities will remain in place after the sales until the purchasers issue similar guarantees to replace them. The guarantees, related to asset retirement obligations and natural gas production levels, have been indemnified by the purchasers. The fair value of these guarantees is not significant.

Norwegian disposition – On October 31, 2008, we closed the sale of our Norwegian outside-operated E&P properties and undeveloped offshore acreage in the Heimdal area of the Norwegian North Sea for net proceeds of $301 million, with a pretax gain of $254 million as of December 31, 2008.

Pilot Travel Centers disposition – On October 8, 2008, we completed the sale of our 50 percent ownership interest in PTC. Sale proceeds were $625 million, with a pretax gain on the sale of $126 million. Immediately preceding the sale, we received a $75 million partial redemption of our ownership interest from PTC that was accounted for as a return of investment. This was an investment of our RM&T segment.

Russia disposition – On June 2, 2006, we sold our Russian oil exploration and production businesses in the Khanty-Mansiysk region of western Siberia. Under the terms of the agreement, we received $787 million for these businesses, plus preliminary working capital and other closing adjustments of $56 million, for a total transaction value of $843 million. Proceeds net of transaction costs and cash held by the Russian businesses at the transaction date totaled $832 million. Adjustments to the sales price were completed in 2007 and an additional pretax gain on the sale of $13 million ($8 million after income taxes) was reported in discontinued operations.

8. 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 assumes exercise of stock options and stock appreciation rights, provided the effect is not antidilutive.

	2009		2008		2007	
(In millions except per share data)	Basic	Diluted	Basic	Diluted	Basic	Diluted
Income from continuing operations	$ 1,184	$ 1,184	$ 3,384	$ 3,384	$ 3,766	$ 3,766
Discontinued operations	279	279	144	144	190	190
Net income	$ 1,463	$ 1,463	$ 3,528	$ 3,528	$ 3,956	$ 3,956
Weighted average common shares outstanding	709	709	709	709	690	690
Effect of dilutive securities	-	2	-	4	-	5
Weighted average common shares, including dilutive effect	709	711	709	713	690	695
Per share:						
Income from continuing operations	$ 1.67	$ 1.67	$ 4.77	$ 4.75	$ 5.46	$ 5.42
Discontinued operations	$ 0.39	$ 0.39	$ 0.20	$ 0.20	$ 0.27	$ 0.27
Net income	$ 2.06	$ 2.06	$ 4.97	$ 4.95	$ 5.73	$ 5.69

The per share calculations above exclude 10 million, 5 million and 3 million stock options and stock appreciation rights in 2009, 2008 and 2007 that were antidilutive.

9. Segment Information

We have four reportable operating segments: Exploration and Production; Oil Sands Mining; Integrated Gas and Refining, Marketing and Transportation. Each of these segments is organized and managed based upon the nature of the products and services they offer.

- Exploration and Production ("E&P") – explores for, produces and markets liquid hydrocarbons and natural gas on a worldwide basis;
- Oil Sands Mining ("OSM") – mines, extracts and transports bitumen from oil sands deposits in Alberta, Canada, and upgrades the bitumen to produce and market synthetic crude oil and vacuum gas oil;
- Integrated Gas ("IG") – markets and transports products manufactured from natural gas, such as LNG and methanol, on a worldwide basis, and is developing other projects to link stranded natural gas resources with key demand areas; and
- 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 U.S.

Information regarding assets by segment is not presented because it is not reviewed by the chief operating decision maker ("CODM"). Segment income represents income from continuing operations, net of income taxes, attributable to the operating segments. Our corporate general and administrative costs are not allocated to the operating segments. These costs primarily consist of employment costs (including pension effects), professional services, facilities and other costs associated with corporate activities, net of associated income tax effects. Foreign currency remeasurement and transaction gains or losses are not allocated to operating segments. Non-cash gains and losses on two natural gas sales contracts in the United Kingdom that were accounted for as derivative instruments, impairments or other items that affect comparability (as determined by the CODM) also are not allocated to operating segments.

Revenues from external customers are attributed to geographic areas based on selling location. No single customer accounts for more than 10 percent of annual revenues.

(In millions)	E&P[(a)]	OSM	IG	RM&T	Total
2009					
Revenues:					
Customer	$ 7,241	$ 549	$ 50	$ 45,461	$ 53,301
Intersegment [(b)]	551	118	-	31	700
Related parties	59	-	-	38	97
Segment revenues	7,851	667	50	45,530	54,098
Elimination of intersegment revenues	(551)	(118)	-	(31)	(700)
Gain on U.K. natural gas contracts[(c)]	72	-	-	-	72
Total revenues	$ 7,372	$ 549	$ 50	$ 45,499	$ 53,470
Segment income	$ 1,221	$ 44	$ 90	$ 464	$ 1,819
Income from equity method investments[(d)]	125	-	144	29	298
Depreciation, depletion and amortization [(e)]	1,795	124	3	670	2,592
Income tax provision [(e)]	1,563	6	39	234	1,842
Capital expenditures [(f)(g)]	2,162	1,115	2	2,570	5,849

(In millions)	E&P[(a)]	OSM	IG	RM&T	Total
2008					
Revenues:					
Customer	$ 11,197	$ 922	$ 93	$ 62,445	$ 74,657
Intersegment [(b)]	798	200	-	209	1,207
Related parties	52	-	-	1,827	1,879
Segment revenues	12,047	1,122	93	64,481	77,743
Elimination of intersegment revenues	(798)	(200)	-	(209)	(1,207)
Gain on U.K. natural gas contracts[(c)]	218	-	-	-	218
Total revenues	$ 11,467	$ 922	$ 93	$ 64,272	$ 76,754
Segment income	$ 2,556	$ 258	$ 302	$ 1,179	$ 4,295
Income from equity method investments[(d)]	225	-	402	178	805
Depreciation, depletion and amortization [(e)]	1,337	143	3	606	2,089
Income tax provision[(e)]	2,827	93	131	684	3,735
Capital expenditures [(f)(g)]	2,971	1,038	4	2,954	6,967

(In millions)	E&P[a]	OSM[h]	IG	RM&T	Total
2007					
Revenues:					
Customer	$ 8,167	$ 181	$ 218	$ 54,137	$ 62,703
Intersegment [b]	497	40	-	348	885
Related parties	35	-	-	1,590	1,625
Segment revenues	8,699	221	218	56,075	65,213
Elimination of intersegment revenues	(497)	(40)	-	(348)	(885)
Loss on U.K. natural gas contracts[c]	(232)	-	-	-	(232)
Total revenues	$ 7,970	$ 181	$ 218	$ 55,727	$ 64,096
Segment income (loss)	$ 1,552	$ (63)	$ 132	$ 2,077	$ 3,698
Income from equity method investments[d]	238	-	168	139	545
Depreciation, depletion and amortization [e]	914	22	6	587	1,529
Income tax provision (benefit)[e]	2,076	(21)	24	1,183	3,262
Capital expenditures [f][g][i]	2,426	165	93	1,640	4,324

(a) As discussed in Note 7, discontinued operations for our Irish and Gabonese businesses in all periods presented and our Russian business in 2007 have been excluded from segment results.
(b) Management believes intersegment transactions were conducted under terms comparable to those with unrelated parties.
(c) The U.K. natural gas contracts expired in September 2009.
(d) Our investment in Pilot Travel Centers LLC, which was reported in our RM&T segment, was sold in the fourth quarter of 2008.
(e) 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.
(f) Differences between segment totals and our totals represent amounts related to corporate administrative activities.
(g) Includes accruals.
(h) As discussed in Note 6, we acquired Western in October 18, 2007.
(i) Through April 2007, Integrated Gas segment capital expenditures include EGHoldings at 100 percent. Effective May 1, 2007, we no longer consolidate EGHoldings and our investment in EGHoldings is accounted for under the equity method of accounting; therefore, EGHoldings' capital expenditures subsequent to April 2007 are not included in our capital expenditures.

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

(In millions)	2009	2008	2007
Segment income	$ 1,819	$ 4,295	$ 3,698
Items not allocated to segments, net of income taxes:			
Corporate and other unallocated items	(422)	(75)	(128)
Foreign currency remeasurement of taxes	(319)	249	19
Impairments[a]	(45)	(1,437)	-
Gain (loss) on U.K. natural gas contracts	37	111	(118)
Gain on dispositions	114	241	-
Gain on foreign currency derivative instruments	-	-	112
Deferred income taxes—tax legislation changes	-	-	193
Loss on early extinguishment of debt	-	-	(10)
Discontinued operations	279	144	190
Net income	$ 1,463	$ 3,528	$ 3,956

(a) Impairments in 2009 reflect a $45 million ($70 million pretax) writeoff of a portion of the contingent proceeds from the sale of the Corrib natural gas development (see Note 7) that was recorded in the fourth quarter of 2009 on the basis of new public information regarding the pipeline that would transport gas from the Corrib development. Impairments in 2008 include the $1,412 million impairment of goodwill related to the OSM reporting unit (see Note 15 to the consolidated financial statements) and the $25 million after-tax impairment ($40 million pretax) related to our investments in ethanol producing companies (see Note 13 to the consolidated financial statements).

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

(In millions)	2009	2008	2007
Total revenues	$ 53,470	$ 76,754	$ 64,096
Less: Sales to related parties	97	1,879	1,625
Sales and other operating revenues (including consumer excise taxes)	$ 53,373	$ 74,875	$ 62,471

The following summarizes revenues from external customers by geographic area.

(In millions)	2009	2008	2007
United States	$ 47,293	$ 69,034	$ 59,302
International	6,177	7,720	4,794
Total revenues	$ 53,470	$ 76,754	$ 64,096

The following summarizes certain long-lived assets by geographic area, including property, plant and equipment and investments.

	December 31,	
(In millions)	2009	2008
United States	$ 18,794	$ 16,298
Canada	8,558	7,775
Equatorial Guinea	2,577	2,732
Other international	4,182	4,719
Total	$ 34,111	$ 31,524

Revenues by product line were:

(In millions)	2009	2008	2007
Refined products	$ 40,518	$ 59,299	$ 49,718
Merchandise	3,308	3,028	2,975
Liquid hydrocarbons	8,253	10,983	8,463
Natural gas	1,265	3,085	2,629
Other products or services	126	359	311
Total revenues	$ 53,470	$ 76,754	$ 64,096

10. Other Items

Net interest and other financing income (costs)

(In millions)	2009	2008	2007
Interest:			
Interest income	$ 11	$ 55	$ 139
Interest expense[a]	(510)	(418)	(275)
Income (loss) on interest rate swaps	17	1	(15)
Interest capitalized	441	305	198
Total interest	(41)	(57)	47
Other:			
Net foreign currency gains (losses)	(36)	40	-
Writeoff off contingent proceeds[b]	(70)	-	-
Other	(2)	(11)	(14)
Total other	(108)	29	(14)
Net interest and other financing income (costs)	$ (149)	$ (28)	$ 33

[a] Excludes $27 million, $29 million and $30 million paid by United States Steel in 2009, 2008 and 2007 on assumed debt.

[b] A portion of he contingent proceeds from the sale of the Corrib natural gas development (see Note 7) was written off in the fourth quarter of 2009 on the basis of new public information regarding the pipeline that would transport gas from the Corrib development. Should further delays occur with respect to commercial first gas, the remaining carrying value of this contingent asset of $15 million may be reduced.

Foreign currency transactions - Aggregate foreign currency gains (losses) were included in the consolidated statements of income as follows:

(In millions)	2009	2008	2007
Net interest and other financing costs	$ (36)	$ 40	$ -
Provision for income taxes	(319)	249	19
Aggregate foreign currency gains (losses)	$ (355)	$ 289	$ 19

11. Income Taxes

Income tax provisions (benefits) were:

	2009			2008			2007		
(In millions)	Current	Deferred	Total	Current	Deferred	Total	Current	Deferred	Total
Federal	$ (224)	$ 162	$ (62)	$ 921	$ 192	$ 1,113	$ 1,289	$ (8)	$ 1,281
State and local	(75)	40	(35)	146	12	158	184	22	206
Foreign	1,484	870	2,354	2,206	(110)	2,096	1,681	(366)	1,315
Total	$ 1,185	$ 1,072	$ 2,257	$ 3,273	$ 94	$ 3,367	$ 3,154	$ (352)	$ 2,802

A reconciliation of the federal statutory income tax rate (35 percent) applied to income from continuing operations before income taxes to the provision for income taxes follows:

	2009	2008	2007
Statutory rate applied to income from continuing operations before income taxes	35 %	35 %	35 %
Effects of foreign operations, including foreign tax credits[a]	12	21	11
Foreign currency remeasurement (gain) loss	10	(4)	-
Effects of nondeductible goodwill impairment	-	7	-
Adjustments to valuation allowances[b]	8	(10)	-
State and local income taxes, net of federal income tax effects	(1)	2	2
Other	2	(1)	(5)
Provision for income taxes	66 %	50 %	43 %

[a] Includes foreign tax credits but excludes the effects of remeasuring income tax assets and liabilities denominated in foreign currencies. 2009 includes foreign tax credit benefits related to crediting certain foreign taxes that were previously considered deductible for U.S. tax purposes.

[b] In 2009, it was determined that we may not be able to realize all recorded foreign tax credit benefits and therefore a valuation allowance was recorded against these benefits. In 2008, we released the valuation allowance on the Norwegian deferred tax asset associated with operating loss carryforwards upon completion of the operated Alvheim/Vilje development offshore Norway, with first production from Alvheim in June 2008 and from Vilje in July 2008.

Deferred tax assets and liabilities resulted from the following:

	December 31, 2009	December 31, 2008
Deferred tax assets:		
Employee benefits	$ 1,163	$ 918
Operating loss carryforwards[a]	625	1,150
Derivative instruments	-	86
Foreign tax credits	1,934	1,088
Other	177	160
Valuation allowances		
Federal[b]	(280)	-
State	(45)	(50)
Foreign[c]	(157)	(212)
Total deferred tax assets	3,417	3,140
Deferred tax liabilities		
Property, plant and equipment	5,862	4,679
Inventories	615	649
Investments in subsidiaries and affiliates	1,330	1,361
Derivative instruments	33	63
Other	75	-
Total deferred tax liabilities	7,915	6,752
Net deferred tax liabilities	$ 4,498	$ 3,612

[a] At December 31, 2009, foreign operating loss carryforwards primarily include $118 million for Norway special petroleum tax and $847 million for Angola income tax. The Norway and Angola operating loss carryforwards have no expiration dates. The remainder of foreign carryforwards were in several other foreign jurisdictions, the majority of which expire in 2010 through 2020. State operating loss carryforwards of $1,196 million expire in 2010 through 2028. The state operating loss carryforwards primarily relate to net operating losses generated during 2009 and the periods prior to the USX Separation. Loss carryforward amounts related to the USX Separation are offset by valuation allowances.

[b] Our expectation regarding our ability to realize the benefit of foreign tax credits is based on certain assumptions concerning future operating conditions (particularly as related to prevailing commodity prices) and income generated from foreign sources. Federal valuation allowances increased $280 million in 2009, decreased $29 million in 2008 and increased $10 million in 2007 due to changes in the expected realizability of foreign tax credits.

[c] Foreign valuation allowances decreased $55 million in 2009, primarily due to the reduction of net operating loss carryforwards as a result of the dispositon of exploration and production businesses in Ireland. Foreign valuation allowances decreased $705 million in 2008, primarily due to the release of the Norwegian valuation allowance. Foreign valuation allowances increased $306 million in 2007 primarily as a result of net operating loss carryforwards generated in Norway, Angola and several other jurisdictions.

Net deferred tax liabilities were classified in the consolidated balance sheet as follows:

	December 31,	
(In millions)	2009	2008
Assets:		
Other current assets	$ 3	$ 36
Other noncurrent assets	6	243
Liabilities:		
Current deferred income taxes	403	561
Noncurrent deferred income taxes	4,104	3,330
Net deferred tax liabilities	$ 4,498	$ 3,612

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 December 31, 2009, our income tax returns remain subject to examination in the following major tax jurisdictions for the tax years indicated:

United States[a]	2001 - 2008
Canada[b]	2002 - 2008
Equatorial Guinea	2006 - 2008
Libya	2006 - 2008
Norway	2008
United Kingdom	2007 - 2008

[a] Includes federal and state jurisdictions.
[b] Tax years to 2001 have been audited, but remain subject to reexamination due to the existence of net operating losses.

We adopted the revised accounting standard for uncertainty in income taxes as of January 1, 2007. Total unrecognized tax benefits were $75 million, $39 million and $40 million as of December 31, 2009, 2008 and 2007. If the unrecognized tax benefits as of December 31, 2009 were recognized, $68 million would affect our effective income tax rate. There were $7 million of uncertain tax positions as of December 31, 2009 for which it is reasonably possible that the amount of unrecognized tax benefits would decrease during 2010.

The following table summarizes the activity in unrecognized tax benefits:

(In millions)	2009	2008	2007
January 1 balance	$ 39	$ 40	$ 48
Additions based on tax positions related to the current year	30	-	11
Reductions based on tax positions related to the current year	(2)	-	-
Additions for tax positions of prior years	30	24	30
Reductions for tax positions of prior years	(15)	(26)	(30)
Settlements	(7)	1	(19)
December 31 balance	$ 75	$ 39	$ 40

In 2007, also under the revised accounting standard, we changed the presentation of interest and penalties related to income taxes in the consolidated statement of income. Effective January 1, 2007, such interest and penalties are prospectively recorded as part of the provision for income taxes. Prior to January 1, 2007, such interest was recorded as part of net interest and other financing costs and such penalties as selling, general and administrative expenses. Interest and penalties were expenses of less than $1 million in the year ended

December 31, 2009 and were a net $14 million and $8 million credit to income for the years ended December 31, 2008 and 2007. As of December 31, 2009, 2008 and 2007, $7 million, $8 million and $15 million of interest and penalties were accrued related to income taxes.

Pretax income from continuing operations included amounts attributable to foreign sources of $2,947 million in 2009, $4,029 million in 2008, and $2,619 million in 2007.

Undistributed income of certain consolidated foreign subsidiaries at December 31, 2009 amounted to $1,903 million for which no deferred U.S. income tax provision has been recorded because we intend to permanently reinvest such income in those foreign operations. If such income was not permanently reinvested, income tax expense of up to $666 million would be recorded.

12. Inventories

	December 31,	
(In millions)	2009	2008
Liquid hydrocarbons, natural gas and bitumen	$1,393	$1,376
Refined products and merchandise	1,790	1,797
Supplies and sundry items	439	334
Total, at cost	$3,622	$3,507

The LIFO method accounted for 85 percent and 90 percent of total inventory value at December 31, 2009 and 2008. Current acquisition costs were estimated to exceed the LIFO inventory value at December 31, 2009 and 2008 by $3,115 million and $777 million.

13. Equity Method Investments

	Ownership as of	December 31,	
(In millions)	December 31, 2009	2009	2008
EGHoldings	60%	$ 986	$1,053
Alba Plant LLC	52%	317	315
Atlantic Methanol Production Company LLC	45%	224	235
LOOP LLC	51%	149	143
Ethanol investments	(a)	62	70
Other		232	264
Total		$1,970	$2,080

(a) As discussed in Note 5, Ethanol investments represent our 35 percent ownership in The Andersons Clymers Ethanol LLC and our 50 percent ownership in The Anderson Marathon Ethanol LLC. Our Ethanol investments were impaired by $40 million ($25 million, net of tax), in 2008, due to an other-than-temporary loss in value as a result of declining demand and prices for ethanol, a poor outlook for short-term future profitability and, in the case of one production facility, recurring operating losses.

Summarized financial information for equity method investees is as follows:

(In millions)	2009	2008	2007
Income data – year:			
Revenues and other income	$1,916	$15,766	$14,133
Income from operations	677	1,608	1,098
Net income	576	1,436	1,038
Balance sheet data – December 31:			
Current assets	$ 802	$ 837	
Noncurrent assets	4,266	4,692	
Current liabilities	767	993	
Noncurrent liabilities	807	821	

As of December 31, 2009, the carrying value of our equity method investments was $301 million higher than the underlying net assets of investees. This basis difference is being amortized into net income over the remaining estimated useful lives of the underlying net assets, except for $49 million of the excess related to goodwill.

Dividends and partnership distributions received from equity method investees (excluding distributions that represented a return of capital previously contributed) were $340 million in 2009, $827 million in 2008 and $502 million in 2007. In 2008 we received a $75 million partial redemption of our partnership interest from Pilot Travel Centers that was accounted for as a return of our investment.

14. Property, Plant and Equipment

	December 31,	
(In millions)	2009	2008
Exploration and production	$23,436	$22,497
Oil sands mining and bitumen upgrading	8,595	7,935
Refining	11,522	9,026
Marketing	2,098	2,144
Transportation	2,703	2,592
Other	952	801
Total	$49,306	$44,995
Less accumulated depreciation, depletion and amortization	17,185	15,581
Net property, plant and equipment	$32,121	$29,414

Property, plant and equipment includes gross assets acquired under capital leases of $247 million and $82 million at December 31, 2009 and 2008, with related amounts in accumulated depreciation, depletion and amortization of $26 million and $18 million at December 31, 2009 and 2008.

Property impairments were $19 million, $21 million and $19 million in 2009, 2008 and 2007. The economic and commodity price declines in the latter part of 2008 and weak natural gas prices in 2009 caused us to assess the carrying value of our assets. No significant impairments resulted due to the cash flows these assets are expected to generate. Should market conditions continue to deteriorate or commodity prices continue to decline, further assessment of the carrying value of assets may be necessary.

Deferred exploratory well costs were as follows:

(In millions)	December 31, 2009	2008	2007
Amounts capitalized less than one year after completion of drilling	$679	$863	$683
Amounts capitalized greater than one year after completion of drilling	150	54	100
Total deferred exploratory well costs	$829	$917	$783
Number of projects with costs capitalized greater than one year after completion of drilling	3	2	3

Exploratory well costs capitalized greater than one year after completion of drilling as of December 31, 2009 included $84 million for the Stones appraisal well incurred in 2008, $36 million for the Gunflint/Freedom appraisal well incurred in 2008 and $30 million related to wells in Equatorial Guinea (primarily Corona and Gardenia) that was primarily incurred in 2004.

The Minerals Management Service (MMS) has approved a plan for the Stones prospect. Engineering and data-gathering efforts continue to progress according to the approved plan. Various development alternatives are being evaluated and optimization efforts continue.

Appraisal drilling for the Gunflint/Freedom prospect will commence in 2010 and continue into 2011. The results of the appraisal well program will be used to evaluate the commercial viability of the project.

The Equatorial Guinea discovery wells are part of our long-term LNG strategy. These discoveries will be developed when the natural gas supply from the nearby Alba Field starts to decline.

The net changes in deferred exploratory well costs were as follows:

(In millions)	2009	2008	2007
Beginning Balance	$ 917	$ 783	$470
Additions	155	413	394
Dry well expense	(32)	(63)	(39)
Transfers to development	(211)	(216)	(42)
Ending Balance	$ 829	$ 917	$783

15. Goodwill

Goodwill is tested for impairment on an annual basis, or when events or changes in circumstances indicate the fair value of a reporting unit with goodwill has been reduced below the carrying value. We performed our annual impairment test during 2009 and no impairment was required. The fair value of our reporting units exceeded the book value appreciably for each of our reporting units.

We performed our 2008 annual goodwill impairment test during the second quarter for our E&P reporting unit, during the third quarter for our OSM reporting unit and during the fourth quarter for our reporting units comprising the RM&T segment, at which time no impairment to the carrying value of goodwill was identified. We tested goodwill for impairment again in the fourth quarter of 2008 for our E&P and OSM reporting units because of the late 2008 disruption in the credit and equity markets and the significant change in commodity prices impacted several of the significant assumptions used in our determination of fair value.

Since limited market-based data was available, we principally used an income based discounted cash flow model to compute the fair value of our reporting units. In applying this valuation method, there was a significant amount of judgment required, involving estimates regarding amount and timing of future production, commodity prices and the discount rate appropriate for each reporting unit. We used our planning and capital investment projections, which consider factors such as a combination of proved and risk-adjusted probable and possible reserves, expected future commodity prices and operating costs. An appropriate discount rate was selected for the each of the reporting units. We also compared our significant assumptions used to determine the fair value amounts against other market-based information, if available. In addition, we considered several fair value determination scenarios using key assumption sensitivities to corroborate our fair value estimates.

Testing goodwill for impairment is a two step process. The first step of the goodwill impairment test, used to identify potential impairment, compares the fair value of a reporting unit with its carrying amount, including goodwill. If the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is not considered to be impaired, thus the second step of the impairment test is unnecessary. If the carrying amount of a reporting unit exceeds its fair value, the second step of the goodwill impairment test is performed to measure the amount of impairment, if any. Our fourth quarter 2008 fair value estimate for the OSM reporting unit was less than the carrying amount.

The second step of the goodwill impairment test, used to measure the amount of impairment loss, compares the implied fair value of reporting unit goodwill with the carrying amount of that goodwill. The implied fair value of goodwill shall be determined in the same manner as the amount of goodwill recognized in a business combination. This requires a hypothetical purchase price to be established as if the fair value of the reporting unit was the current price paid to acquire the reporting unit. To determine what the implied fair value of the recorded goodwill would be, the fair value for that reporting unit is hypothetically allocated to all assets and liabilities within that reporting unit. If the carrying amount of reporting unit goodwill exceeds the implied fair value of that goodwill, an impairment loss is required to be recognized in an amount equal to that excess.

The second step in the goodwill impairment process indicated there was no remaining implied fair value of goodwill as of December 31, 2008, for the OSM reporting unit. This was largely due to the recent disruption in the credit and equity markets, which impacts discount rate assumptions, a change in the timing of expected production and the decline in commodity prices. As a result, a $1,412 million impairment of goodwill for the OSM reporting unit was recorded and reported on a separate line of our consolidated statement of income for 2008.

While the fair values of our other reporting units exceed the carrying value at the present time, should market conditions deteriorate or commodity prices decline, the goodwill of our other reporting units could require impairment.

The changes in the carrying amount of goodwill for the years ended December 31, 2009, and 2008, were as follows:

(In millions)	E&P	OSM	RM&T	Total
2008				
Beginning balance	$590	$ 1,437	$872	$ 2,899
Impairment	-	(1,412)	-	(1,412)
Deferred tax adjustments	(17)	(9)	-	(26)
Purchase price adjustments	-	(16)	-	(16)
Contingent consideration adjustment	-	-	7	7
Dispositions	(5)	-	-	(5)
Ending balance	568	-	879	1,447
2009				
Beginning balance, gross	568	1,412	879	2,859
Less: accumulated impairments	-	(1,412)	-	(1,412)
Beginning balance, net	568	-	879	1,447
Deferred tax adjustments	-	-	9	9
Contingent consideration adjustment	-	-	(1)	(1)
Dispositions	(31)	-	(2)	(33)
Ending balance, net	$537	$ -	$885	$ 1,422

16. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. There are three approaches for measuring the fair value of assets and liabilities: the market approach, the income approach and the cost approach, each of which includes multiple valuation techniques. The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. The income approach uses valuation techniques to measure fair value by converting future amounts, such as cash flows or earnings, into a single present value amount using current market expectations about those future amounts. The cost approach is based on the amount that would currently be required to replace the service capacity of an asset. This is often referred to as current replacement cost.

The cost approach assumes that the fair value would not exceed what it would cost a market participant to acquire or construct a substitute asset of comparable utility, adjusted for obsolescence.

The fair value accounting standards do not prescribe which valuation technique should be used when measuring fair value and does not prioritize among the techniques. These standards establish a fair value hierarchy that prioritizes the inputs used in applying the various valuation techniques. Inputs broadly refer to the assumptions that market participants use to make pricing decisions, including assumptions about risk. Level 1 inputs are given the highest priority in the fair value hierarchy while Level 3 inputs are given the lowest priority. The three levels of the fair value hierarchy are as follows.

- Level 1 – Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2 – Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date.
- Level 3 – Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

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

The following tables present net assets and liabilities accounted for at fair value on a recurring basis as of December 31, 2009 and 2008:

	December 31, 2009			
(In millions)	Level 1	Level 2	Level 3	Total
Derivative instruments:				
Commodity	$16	$55	$ 1	$72
Interest rate	-	-	5	5
Foreign currency	-	1	2	3
Total derivative instruments	16	56	8	80
Other assets	3	-	-	3
Total at fair value	$19	$56	$ 8	$83

	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 $63 million and $121 million in broker accounts covered by master netting agreements are included in the Level 1 and Level 2 fair values of commodity derivatives as of December 31, 2009 and 2008. 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.

Derivatives in Level 3 at December 31, 2009 include interest rate derivatives which are measured at fair value using quotes from a reporting service. In addition, the fair value of the foreign currency options is measured using an option pricing model for which the inputs come from a reporting service. Because we are unable to independently verify those inputs obtained from a service directly to an active market, such inputs are considered Level 3.

Commodity derivatives in Level 3 at December 31, 2008 included a $72 million liability related to two U.K. natural gas sales contracts that were accounted for as derivative instruments and a $52 million asset for crude oil options related to sales of Canadian synthetic crude oil. The fair value of the U.K. natural gas contracts was measured with an income approach by applying the difference between the contract price and the U.K. forward natural gas strip price to the expected sales volumes for the remaining contract term. These contracts originated in the early 1990s and expired in September 2009. The contract prices were 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 did not track forward natural gas prices. The crude oil options, which expired December 2009, were measured at fair value using a Black-Scholes option pricing model, an income approach that used prices from an active market and market volatility calculated by a third-party service.

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

	December 31,	
(In millions)	2009	2008
Beginning balance	$(26)	$(355)
Total realized and unrealized losses (gains):		
Included in net income	68	210
Included in other comprehensive income	(1)	1
Purchases, sales, issuances and settlements, net	(33)	118
Ending balance	$ 8	$ (26)

Net income for the years ended December 31, 2009 and 2008 included unrealized losses of $7 million and an unrealized gain of $299 million related to instruments held on those dates. See Note 17 for the impacts of our derivative instruments on our consolidated statements of income.

Fair Values – Nonrecurring

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

	Year Ended December 31, 2009	
(In millions)	Fair Value	Impairment
Long-lived assets held for use	$ 5	$ 15
Long-lived assets held for sale	311	154

Several long-lived assets held for use were evaluated for impairment during 2009 due to reductions in estimated reserves and declining natural gas prices. The fair values of the assets were measured using an income approach based upon internal estimates of future production levels, prices and discount rate, which are Level 3 inputs. An impairment was recorded for one natural gas field in east Texas.

The $154 million impairment charge recorded on assets held for sale in the second quarter of 2009 related to the sale of the Corrib natural gas development offshore Ireland and was based on a $311 million fair value of anticipated sale proceeds (see Note 7). Fair value of anticipated sale proceeds includes (1) $100 million received at closing, (2) $135 million minimum amount due at the earlier of first gas or December 31, 2012, and (3) a range of zero to $165 million of contingent proceeds subject to the timing of first commercial gas. The fair value of the total proceeds was measured 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. Because a portion of the proceeds is variable in timing and amount depending upon timing of first commercial gas, the inputs to the fair value calculation were classified as Level 3 inputs.

The following table summarizes financial instruments, excluding the derivative financial instruments reported above, by individual balance sheet line item at December 31, 2009 and 2008.

	December 31,			
	2009		2008	
(In millions)	Fair Value	Carrying Amount	Fair Value	Carrying Amount
Financial assets				
Receivables from United States Steel, including current portion	$ 360	$ 346	$ 438	$ 492
Other noncurrent assets[(a)]	334	178	260	91
Total financial assets	694	524	698	583
Financial liabilities				
Long-term debt, including current portion[(b)]	8,754	8,190	5,683	6,907
Deferred credits and other liabilities[(c)]	49	49	55	55
Total financial liabilities	$8,803	$8,239	$5,738	$6,962

(a) Includes cost method investments, miscellaneous long-term receivables or deposits and restricted cash.
(b) Excludes capital leases.
(c) Includes long-term liabilities related to contract terminations.

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 are reported above. Our fair value assessment incorporates a variety of considerations, including (1) the short-term duration of the instruments (e.g., less than 1 percent of our trade receivables and payables are outstanding for greater than 90 days), (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 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 the tenth anniversary of the USX Separation per the Financial Matters Agreement.

The majority of our restricted cash represent cash accounts that earn interest; therefore, the balance approximates fair value. Other financial assets included in our 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 our internal forecasts or forecasts from the partially owned companies, are discounted to obtain the fair value. Long-term receivables and deposits are also measured using an income approach. The expected timing of payments is scheduled and then discounted using a rate deemed appropriate.

Over 90 percent of our long-term debt instruments are publicly-traded. A market approach, based upon quotes from major financial institutions is used to measure the fair value of such debt. Because these quotes cannot be independently verified to 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.

17. Derivatives

For further information regarding the fair value measurement of derivative instruments see Note 16. See our Note 1 for discussion of the types of derivatives we use and the reasons for them. 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 December 31, 2009:

(In millions)	Asset	Liability	**Net Asset**	Balance Sheet Location
Cash Flow Hedges				
Foreign currency	$ 2	$ -	$ 2	Other current assets
Fair Value Hedges				
Interest rate	8	(3)	5	Other noncurrent assets
Total Designated Hedges	10	(3)	7	
Not Designated as Hedges				
Foreign currency	1	-	1	Other current assets
Commodity	116	(104)	12	Other current assets
Total Not Designated as Hedges	117	(104)	13	
Total	$ 127	$ (107)	$ 20	

(In millions)	Asset	Liability	**Net Liability**	Balance Sheet Location
Cash Flow Hedges				
Foreign currency	$ -	$ -	$-	Other current liabilities
Fair Value Hedges				
Commodity	-	(1)	(1)	Other current liabilities
Total Designated Hedges	-	(1)	(1)	
Not Designated as Hedges				
Commodity	13	(15)	(2)	Other current liabilities
Total Not Designated as Hedges	13	(15)	(2)	
Total	$13	$(16)	$(3)	

Derivatives Designated as Cash Flow Hedges

As of December 31, 2009, the following foreign currency forwards and options were designated as cash flow hedges:

(In millions)	Settlement Period	Notional Amount	Weighted Average Forward Rate
Foreign Currency Forwards Dollar (Canada)	January 2010 - February 2010	$ 24	1.062 [(a)]

[(a)] U.S. dollar to foreign currency.

(In millions)	Period	Notional Amount	Weighted Average Exercise Price
Foreign Currency Options Dollar (Canada)	January 2010 - September 2010	$ 144	1.042 [(a)]

[(a)] U.S. dollar to foreign currency.

Approximately $2 million in losses are expected to be reclassified from accumulated other comprehensive income ("AOCI") over the next 12 months. Ineffectiveness related to cash flow hedges was a $1 million loss in 2009.

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

(In millions)	Gain (Loss) in OCI 2009
Foreign currency	$ 39
Interest rate	$(15)

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

(In millions)	Income Statement Location	Gain (Loss) Reclassified from AOCI into Net Income 2009
Foreign currency	Discontinued operations	$ 1
Foreign currency	Depreciation, depletion and amortization	$ 1
Interest rate	Net interest and other financing income (costs)	$ (3)

Derivatives Designated as Fair Value Hedges

As of December 31, 2009, we had multiple interest rate swap agreements with a total notional amount of $1.35 billion at a weighted-average, LIBOR-based, floating rate of 4.37 percent. As of December 31, 2009, we also had commodity derivative instruments for a weighted average 5,000 mcfd ("thousand cubic feet per day") outstanding for the period January 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 2009:

(In millions)	Income Statement Location	Gain (Loss) 2009
Derivative		
Commodity	Sales and other operating revenues	$ (16)
Interest rate	Net interest and other financing income (costs)	-
		(16)
Hedged Item		
Commodity	Sales and other operating revenues	16
Long-term debt	Net interest and other financing income (costs)	-

The interest rate swaps have no hedge ineffectiveness. Hedge ineffectiveness related to the commodity derivatives was less than $1 million in 2009.

Derivatives not Designated as Hedges

The two U.K. natural gas sales contracts that were accounted for as derivative instruments and the crude oil options related to the acquisition of Western Oil Sands Inc. expired in 2009.

During 2009, hedge accounting was discontinued prospectively for Kroner (Norway) and Euro foreign currency forwards when it was determined that they were no longer highly effective hedges. The Kroner contracts expired in 2009. The Euro contracts remain in place and prospective changes in the fair value of the derivative contracts will be recognized in net interest and other financing income (costs). Ineffectiveness on these hedges of $3 million was recorded as a gain to net interest and other financing income (costs) in 2009.

As of December 31, 2009, the following foreign currency forwards not designated as hedges were outstanding:

(In millions)	Settlement Period	Notional Amount	Weighted Average Forward Rate
Foreign Currency Forwards			
Euro	March 2010 - June 2010	$ 3	1.278[a]

[a] Foreign currency to U.S. dollar.

The following table summarizes volumes related to our net open commodity derivatives that are not designated as hedges as of December 31, 2009:

	Buy/(Sell)
Crude oil (million barrels)	(14.6)
Refined products (million barrels)	(1.5)
Natural gas (billion cubic feet)	
Price	(41.7)
Basis	(41.8)

The following table summarizes the effect of all derivative instruments not designated as hedges in our consolidated statement of income for 2009:

(In millions)	Income Statement Location	Gain (Loss) 2009
Commodity	Sales and other operating revenues	$ 76
Commodity	Cost of revenues	(70)
Commodity	Other income	12
Foreign currency	Net interest and other financing income (costs)	3
		$ 21

Derivative instruments reported in previous years

Accounting standards expanding the disclosure requirements for derivative instruments and hedging activities were effective January 1, 2009, and encouraged, but did not require, disclosures for earlier periods presented for comparative purposes at initial adoption. Reporting for prior-year derivatives is therefore carried forward. For more information regarding the expanded requirements, see Note 2.

The following table sets forth quantitative information by category of derivative instrument at December 31, 2008. These amounts are reported on a gross basis by individual derivative instrument.

(In millions)	2008 Assets	2008 (Liabilities)
Commodity Instruments		
Fair value hedges:[a]		
Commodity swaps	$ -	$ (12)
Non-hedge designation:		
Exchange-traded commodity futures	279	(277)
Exchange-traded commodity options	16	(18)
Commodity swaps	25	(55)
Commodity options	65	(14)
U.K. natural gas contracts[b]	-	(72)
Financial Instruments		
Fair value hedges:		
Interest rate swaps[c]	29	-
Cash flow hedges:[d]		
Foreign currency forwards	$ 2	$ (77)

(a) There was no ineffectiveness associated with fair value hedges for 2008 because the hedging instruments and the existing firm commitment contracts were priced on the same underlying index.

(b) The contract price under the U.K. natural gas contracts was reset annually and was indexed to a basket of costs of living and energy commodity indices for the previous 12 months. The fair value of these contracts was determined by applying the difference between the contract price and the U.K. forward natural gas strip price to the expected sales volumes under these contracts. The U.K. natural gas contracts expired September 2009.

(c) The fair value of interest rate swaps excludes accrued interest amounts not yet settled. As of December 31, 2008, accrued interest was a receivable of $1 million. The net fair value of the OTC interest rate swaps as of December 31, 2008 is included in long-term debt. See Note 19.

(d) The changes in fair value of cash flow hedges included less than $1 million ineffectiveness during 2008.

Pretax derivative gains and losses included in net income for 2008 and 2007 are summarized in the following table:

(In millions)	2008	2007
Derivative gains (losses):		
E&P segment revenues	$ 22	$ (15)
OSM segment revenues	48	(54)
RM&T segment revenues	(89)	(900)
U.K. natural gas contracts not allocated to the segments	218	(232)
Total net derivative gains (losses)	$199	$(1,201)

18. Short Term Debt

We have a commercial paper program that is supported by the unused credit on our revolving credit facility discussed in Note 19. At December 31, 2009 and 2008, there were no commercial paper borrowings outstanding.

19. Long Term Debt

Our long term debt agreements do not contain restrictive financial covenants.

(In millions)	December 31, 2009	December 31, 2008
Marathon Oil Corporation:		
Revolving credit facility due 2012[a]	$ -	$ -
6.125% notes due 2012[b]	450	450
6.000% notes due 2012[b]	400	400
5.900% notes due 2018[c]	1,000	1,000
6.800% notes due 2032[b]	550	550
9.375% debentures due 2012	87	87
9.125% debentures due 2013	174	174
6.500% debentures due 2014[d]	700	-
7.500% debentures due 2019[d]	800	-
6.000% debentures due 2017[b]	750	750
9.375% debentures due 2022	65	65
8.500% debentures due 2023	116	116
8.125% debentures due 2023	172	172
6.600% debentures due 2037[b]	750	750
4.550% promissory note, semi-annual payments due 2010 - 2015	408	476
Series A medium term notes due 2022	3	3
4.750% - 6.875% obligations relating to industrial development and environmental improvement bonds and notes due 2013 - 2033[e]	310	439
5.125% obligation relating to revenue bonds due 2037	1,000	1,000
Sale-leaseback financing due 2010 - 2012[f]	29	37
Capital lease obligation due 2010 - 2012[g]	25	32
Consolidated subsidiaries		
8.375% secured notes due 2012[b] [h]	448	448
Capital lease obligations due 2010 - 2020[i]	265	183
Total[j] [k]	8,502	7,132
Unamortized fair value differential for debt assumed in acquisitions	27	37
Unamortized discount	(20)	(13)
Fair value adjustments [l]	23	29
Amounts due within one year	(96)	(98)
Total long-term debt due after one year	$8,436	$7,087

(a) During 2008, we entered into an amendment of our $3.0 billion revolving credit facility, extending the termination date on $2,625 million from May 2012 to May 2013. The remaining $375 million continues to have a termination date of May 2012. The facility requires a representation at an initial borrowing that there has been no change in our consolidated financial position or operations, considered as a whole which would materially and adversely affect our ability to perform our obligations under the revolving credit facility. Interest on the facility is based on defined short-term market rates. During the term of the agreement, we are obligated to pay a variable facility fee on the total commitment, which at December 31, 2009 was 0.08 percent.

(b) These notes contain a make-whole provision allowing us the right to repay the debt at a premium to market price.

(c) In 2008, we issued $1.0 billion aggregate principal amount of senior notes bearing interest at 5.9 percent with a maturity date of March 15, 2018. Interest on the senior notes is payable semi-annually beginning September 15, 2008.

(d) In 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 is payable semi-annually beginning August 15, 2009.

(e) United States Steel has assumed responsibility for repayment of $286 million of these obligations. The Financial Matters Agreement provides that, on or before the tenth anniversary of the USX Separation, United States Steel will provide for our discharge from any remaining liability under any of the assumed industrial revenue bonds. In 2009, US Steel refinanced and paid off $129 million face value of these bonds.

(f) This sale-leaseback financing arrangement relates to a lease of a slab caster at United States Steel's Fairfield Works facility in Alabama. We are the primary obligor under this lease. Under the Financial Matters Agreement, United States Steel has assumed responsibility for all obligations under this lease. This lease is an amortizing financing with a final maturity of 2012, subject to additional extensions.

(g) This obligation relates to a lease of equipment at United States Steel's Clairton Works cokemaking facility in Pennsylvania. We are the primary obligor under this lease. Under the Financial Matters Agreement, United States Steel has assumed responsibility for all obligations under this lease. This lease is an amortizing financing with a final maturity of 2012.

(h) These notes are senior secured notes of Marathon Oil Canada Corporation. The notes are secured by substantially all of Marathon Oil Canada Corporation's assets. In January 2008, we provided a full and unconditional guarantee covering the payment of all principal and interest due under the senior notes.

(i) These obligations as of December 31, 2009 include $36 million related to assets under construction at that date for which a capital lease will commence upon completion of construction. The amounts currently reported are based upon the percent of construction completed as of December 31, 2009 and therefore do not reflect future minimum lease obligations of $164 million related to the asset.

(j) Payments of long-term debt for the years 2010 - 2014 are $102 million, $246 million, $1,492 million, $287 million and $802 million. United Steel is due to pay $17 million in 2010, $161 million in 2011, $19 million in 2012, and $11 for year 2014.

(k) In the event of a change in control, as defined in the related agreements, debt obligations totaling $662 million at December 31, 2009, may be declared immediately due and payable.

(l) See Note 16 for information on interest rate swaps.

20. Asset Retirement Obligations

The following summarizes the changes in asset retirement obligations:

(In millions)	2009	2008
Asset retirement obligations as of January 1	$ 965	$ 1,134
Liabilities incurred, including acquisitions	14	30
Liabilities settled	(65)	(94)
Accretion expense (included in depreciation, depletion and amortization)	64	66
Revisions to previous estimates	124	24
Held for sale	-	(195)
Asset retirement obligations as of December 31[(a)]	$ 1,102	$ 965

(a) Includes asset retirement obligation of $3 and $2 million classified as short-term at December 31, 2009, and 2008.

21. Supplemental Cash Flow Information

(In millions)	2009	2008	2007
Net cash provided from operating activities from continuing operations included:			
Interest paid (net of amounts capitalized)	$ 19	$ 92	$ 66
Income taxes paid to taxing authorities	1,663	2,921	3,283
Income tax settlements paid to United States Steel	-	-	13
Commercial paper and revolving credit arrangements, net:			
Commercial paper - issuances	$ 897	$ 46,706	$ 12,751
- repayments	(897)	(46,706)	(12,751)
Credit agreements - borrowings	-	404	-
- repayments	-	(404)	-
Noncash investing and financing activities:			
Additions to property, plant and equipment			
Asset retirement costs capitalized, excluding acquisitions	$ 135	$ 26	$ 8
Change in capital expenditure accrual	(343)	30	621
Debt payments made by United States Steel	144	14	21
Capital lease and sale-leaseback financing obligations increase	86	84	49
Bond obligation assumed for trusteed funds	-	-	1,000
Acquisitions:			
Debt and other liabilities assumed	-	-	1,541
Common stock or securities exchangeable for common stock issued	-	-	1,910
Deconsolidation of EGHoldings:			
Decrease in non-cash assets	-	-	1,759
Equity method investment recorded	-	-	942
Decrease in liabilities	-	-	310
Elimination of minority interests	-	-	544

22. Defined Benefit Postretirement Plans

We have noncontributory defined benefit pension plans covering substantially all domestic employees as well as international employees located in Norway and the United Kingdom. Through 2009, benefits under these plans have been based primarily on years of service and final average pensionable earnings.

We also have defined benefit plans for other postretirement benefits covering most employees. Health care benefits are provided through comprehensive hospital, surgical and major medical benefit provisions subject to various cost-sharing features. Life insurance benefits are provided to certain nonunion and union-represented retiree beneficiaries. Other postretirement benefits are not funded in advance.

Obligations and funded status – The following summarizes the obligations and funded status for our defined benefit pension and other postretirement plans.

	Pension Benefits				Other Benefits	
	2009		2008		2009	2008
(In millions)	U.S.	Int'l	U.S.	Int'l		
Change in benefit obligations:						
Benefit obligations at January 1	$ 2,164	$ 288	$ 2,143	$ 426	$ 694	$ 736
Service cost	130	14	127	19	17	18
Interest cost	146	22	135	25	41	44
Actuarial loss (gain)	703	85	(58)	(72)	(35)	(75)
Plan amendment	-	-	-	1	-	-
Foreign currency exchange rate changes	-	26	-	(99)	-	-
Divestiture[(a)]	-	(30)	-	-	-	
Benefits paid	(154)	(10)	(183)	(12)	(32)	(29)
Benefit obligations at December 31	$ 2,989	$ 395	$ 2,164	$ 288	$ 685	$ 694
Change in plan assets:						
Fair value of plan assets at January 1	$ 1,203	$ 288	$ 1,790	$ 381	$ -	$ -
Actual return on plan assets	257	52	(448)	(28)	-	-
Employer contributions	311	34	44	41	-	-
Foreign currency exchange rate changes	-	28	-	(94)	-	-
Divestiture[(a)]	-	(44)	-	-	-	-
Other	6	-	-	-	-	-
Benefits paid	(154)	(10)	(183)	(12)	-	-
Fair value of plan assets at December 31	$ 1,623	$ 348	$ 1,203	$ 288	$ -	$ -
Funded status of plans at December 31	$ (1,366)	$ (47)	$ (961)	$ -	$ (685)	$ (694)
Amounts recognized in the consolidated balance sheet:						
Current liabilities	(18)	-	(11)	-	(34)	(35)
Noncurrent liabilities	(1,348)	(47)	(950)	-	(651)	(659)
Accrued benefit cost	$ (1,366)	$ (47)	$ (961)	$ -	$ (685)	$ (694)
Pretax amounts in accumulated other comprehensive income:[(b)]						
Net loss (gain)	$ 1,338	$ 71	$ 785	$ 26	$ (53)	$ (23)
Prior service cost (credit)	93	-	106	1	(30)	(36)

(a) The divestiture is related to our discontinued operations in Ireland, as discussed in Note 7

(b) Amount excludes those related to LOOP LLC, an equity method investee with defined benefit pension and postretirement plans for which net losses of $8 million and $10 million were recorded in accumulated other comprehensive income, reflecting our 51 percent share.

The accumulated benefit obligation for all defined benefit pension plans was $2,659 million and $1,975 million as of December 31, 2009 and 2008.

The following summarizes our defined benefit pension plans that have accumulated benefit obligations in excess of plan assets.

	December 31,			
	2009		2008	
(In millions)	U.S.	Int'l	U.S.	Int'l
Projected benefit obligation	$ (2,989)	$ (395)	$ (2,164)	$ -
Accumulated benefit obligation	(2,300)	(359)	(1,711)	-
Fair value of plan assets	1,623	348	1,203	-

Components of net periodic benefit cost and other comprehensive income – The following summarizes the net periodic benefit costs and the amounts recognized as other comprehensive income for our defined benefit pension and other postretirement plans.

	Pension Benefits								
	2009		2008		2007		Other Benefits		
(In millions)	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	2009	2008	2007
Components of net periodic benefit cost:									
Service cost	$ 130	$ 14	$ 127	$ 19	$ 126	$ 14	$ 17	$ 18	$ 22
Interest cost	146	22	135	25	124	18	41	44	45
Expected return on plan assets	(141)	(21)	(142)	(26)	(135)	(19)	-	-	-
Amortization									
- prior service cost (credit)	13	1	13	-	13	-	(5)	(8)	(10)
- actuarial loss	29	2	29	3	36	3	(5)	1	8
Net settlement/curtailment loss[(a)(b)]	4	18	-	-	-	-	-	-	-
Net periodic benefit cost[(c)]	$ 181	$ 36	$ 162	$ 21	$ 164	$ 16	$ 48	$ 55	$ 65
Other changes in plan assets and benefit obligations recognized in other comprehensive income (pretax):									
Actuarial loss (gain)	$ 587	$ 52	$ 532	$ (32)	$ (21)	$ 7	$ (34)	$ (76)	$ (122)
Amortization of actuarial loss	(33)	(7)	(29)	(3)	(36)	(3)	5	(1)	(8)
Prior service cost	-	-	-	1	-	-	5	-	-
Amortization of prior service credit (cost)	(13)	(1)	(13)	-	(13)	-	-	8	10
Total recognized in other comprehensive income	$ 541	$ 44	$ 490	$ (34)	$ (70)	$ 4	$ (24)	$ (69)	$ (120)
Total recognized in net periodic benefit cost and other comprehensive income	$ 722	$ 80	$ 652	$ (13)	$ 94	$ 20	$ 24	$ (14)	$ (55)

(a) A settlement was recorded for one U.S. plan due to lump sum payments exceeding the plan's total service and interest cost expensed in 2009.

(b) A curtailment and settlement were recorded related to our discontinued operations in Ireland, as discussed in Note 7.

(c) Net periodic benefit cost reflects a calculated market-related value of plan assets which recognizes changes in fair value over three years.

The estimated net loss and prior service cost for our defined benefit pension plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2010 are $102 million and $13 million. The 2010 net loss amortization is expected to be higher than the 2009 actual amortization primarily as a result of the decrease in the discount rate as shown in the table below. The estimated net gain and prior service credit for our other defined benefit postretirement plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2010 are $2 million and $6 million.

Plan assumptions – The following summarizes the assumptions used to determine the benefit obligations at December 31, and net periodic benefit cost for the defined benefit pension and other postretirement plans for the 2009, 2008 and 2007.

	Pension Benefits						Other Benefits		
	2009		2008		2007				
(In millions)	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	2009	2008	2007
Weighted average assumptions used to determine benefit obligation:									
Discount rate	5.50%	5.70%	6.90%	6.70%	6.30%	5.80%	5.95%	6.85%	6.60%
Rate of compensation increase	4.50%	5.55%	4.50%	4.75%	4.50%	5.15%	4.50%	4.50%	4.50%
Weighted average assumptions used to determine net periodic benefit cost:									
Discount rate	6.90%	6.70%	6.30%	5.80%	5.81%	5.20%	6.85%	6.60%	5.90%
Expected long-term return on plan assets	8.50%	6.10%	8.50%	6.48%	8.50%	6.45%	-	-	-
Rate of compensation increase	4.50%	4.75%	4.50%	5.15%	4.50%	4.75%	4.50%	4.50%	4.50%

Expected long-term return on plan assets

U.S. plans – The overall expected long-term return on plan assets assumption for our U.S. plans is determined based on an asset rate-of-return modeling tool developed by a third-party investment group. The tool utilizes underlying assumptions based on actual returns by asset category and inflation and takes into account our U.S. pension plans' asset allocation to derive an expected long-term rate of return on those assets. Capital market assumptions reflect the long-term capital market outlook. The assumptions for equity and fixed income investments are developed using a building-block approach, reflecting observable inflation information and interest rate information available in the fixed income markets. Long-term assumptions for other asset categories are based on historical results, current market characteristics and the professional judgment of our internal and external investment teams.

International plans – To determine the overall expected long-term return on plan assets assumption for our international plans, we consider the current level of expected returns on risk-free investments (primarily government bonds), the historical levels of the risk premiums associated with the other applicable asset categories and the expectations for future returns of each asset class. The expected return for each asset category is then weighted based on the actual asset allocation in our international pension plans to develop the overall expected long-term return on plan assets assumption.

Assumed health care cost trend

The following summarizes the assumed health care cost trend rates.

	2009	2008	2007
Health care cost trend rate assumed for the following year:			
Medical			
Pre-65	7.00%	7.00%	7.50%
Post-65	6.75%	7.00%	7.50%
Prescription drugs	7.50%	10.00%	10.50%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate):			
Medical			
Pre-65	5.00%	5.00%	5.00%
Post-65	5.00%	5.00%	5.00%
Prescription drugs	5.00%	6.00%	6.00%
Year that the rate reaches the ultimate trend rate:			
Medical			
Pre-65	2014	2012	2012
Post-65	2015	2012	2012
Prescription drugs	2015	2016	2016

Assumed health care cost trend rates have a significant effect on the amounts reported for defined benefit retiree health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

(In millions)	1-Percentage-Point Increase	1-Percentage-Point Decrease
Effect on total of service and interest cost components	$ 9	$ 7
Effect on other postretirement benefit obligations	88	72

Plan investment policies and strategies

The investment policies for our U.S. and international pension plan assets reflect the funded status of the plans and expectations regarding our future ability to make further contributions. Long-term investment goals are to: (1) manage the assets in accordance with the legal requirements of all applicable laws; (2) produce investment returns which meet or exceed the rates of return achievable in the capital markets while maintaining the risk parameters set by the plans' investment committees and protecting the assets from any erosion of purchasing power; and (3) position the portfolios with a long-term risk/return orientation.

U.S. plans – Historical performance and future expectations suggest that common stocks will provide higher total investment returns than fixed income securities over a long-term investment horizon. Short-term investments only reflect the liquidity requirements for making pension payments. As such, the plans' targeted asset allocation is comprised of 75 percent equity securities and 25 percent fixed income securities. In the second quarter of 2009, we exchanged the majority of our publicly-traded stocks and bonds for interests in pooled equity and fixed income investment funds from our outside manager, representing 58 percent and 20 percent of U.S. plan assets, respectively, as of December 31, 2009. These funds are managed with the same style and strategy as when the securities were held separately. Each fund's main objective is to provide investors with exposure to either a publicly-traded equity or fixed income portfolio comprised of both U.S. and non-U.S. securities. The equity fund holdings primarily consist of publicly-traded individually-held securities in various sectors of many industries. The fixed income fund holdings primarily consist of publicly-traded investment-grade bonds.

The plans' assets are managed by a third-party investment manager. The investment manager has limited discretion to move away from the target allocations based upon the manager's judgment as to current confidence or concern regarding the capital markets. Investments are diversified by industry and type, limited by grade and maturity. The plans' investment policy prohibits investments in any securities in the steel industry and allows derivatives subject to strict guidelines, such that derivatives may only be written against equity securities in the portfolio. Investment performance and risk is measured and monitored on an ongoing basis through quarterly investment meetings and periodic asset and liability studies.

International plans – Our international plans' target asset allocation is comprised of 70 percent equity securities and 30 percent fixed income securities. The plan assets are invested in six separate portfolios, mainly pooled fund vehicles, managed by several professional investment managers. Investments are diversified by industry and type, limited by grade and maturity. The use of derivatives by the investment managers is permitted, subject to strict guidelines. The investment managers' performance is measured independently by a third-party asset servicing consulting firm. Overall, investment performance and risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews and periodic asset and liability studies.

Fair value measurements

Plan assets are measured at fair value. The definition and approaches to measuring fair value and the three levels of the fair value hierarchy are described in Note 16. The following provides a description of the valuation techniques employed for each major plan asset category at December 31, 2009 and 2008.

Cash and cash equivalents – Cash and cash equivalents include cash on deposit and an investment in a money market mutual fund that invests mainly in short-term instruments and cash, both of which are valued using a market approach and are considered Level 1 in the fair value hierarchy. The money market mutual fund is valued at the net asset value ("NAV") of shares held.

Equity securities – Investments in public investment trusts and S&P 500 exchange-traded funds are valued using a market approach at the closing price reported in an active market and are therefore considered Level 1. Non-public investment trusts are valued using a market approach based on the underlying investments in the trust, which are publicly-traded securities, and are considered Level 2. Private equity investments include interests in limited partnerships which are valued based on the sum of the estimated fair values of the investments held by each partnership, determined using a combination of market, income and cost approaches, plus working capital, adjusted for liabilities, currency translation and estimated performance incentives. These private equity investments are considered Level 3.

Mutual funds – Investments in mutual funds are valued using a market approach at the NAV of shares or units held. The NAV is generally based on prices from a public exchange, which is normally the principal market on which a significant portion of the underlying investments are traded, and is considered Level 1.

Pooled funds – Investments in pooled funds are valued using a market approach at the NAV of units held, but investment opportunities in such funds are limited to institutional investors on the behalf of defined benefit plans. The various funds consist of either an equity or fixed income investment portfolio with underlying investments held in U.S. and non-U.S. securities. A significant portion of the underlying investments are publicly-traded. The majority of the pooled funds held by our international pension plans are benchmarked against a relative public index as defined under the plans' investment policies. These investments are considered Level 2.

Real estate – Real estate investments are valued based on discounted cash flows, comparable sales, outside appraisals, price per square foot or some combination thereof and therefore are considered Level 3.

Other – Other investments are composed of an investment in an unallocated annuity contract and investments in two limited liability companies ("LLCs") with no public market. The LLCs were formed to acquire acres of timberland in the southwest and other properties. The investment in an unallocated annuity contract is valued using a market approach based on the experience of the assets held in an insurer's general account and is considered Level 2. The majority of the general account is invested in a well-diversified portfolio of high-quality fixed income securities, primarily consisting of investment-grade bonds. Investment income is allocated among pension plans participating in the general account based on the investment year method. Under this method, a record of the book value of assets held is maintained in subdivisions according to the calendar year in which the funds are invested. The earnings rate for each of these calendar year subdivisions varies from year to year, reflecting the actual earnings on the assets attributed to that year. The values of the LLCs are determined using an income approach based on discounted cash flows and are considered Level 3.

The following table presents the fair values of our defined benefit pension plans' assets, by level within the fair value hierarchy, as of December 31, 2009.

(In millions)	Level 1		Level 2		Level 3		Total	
	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l
Cash and cash equivalents	$ 12	$ 1	$ -	$ -	$ -	$ -	$ 12	$ 1
Equity securities:								
Investment trusts	21	-	114	-	-	-	135	-
Exchange traded funds	26	-	-	-	-	-	26	-
Private equity	-	-	-	-	42	-	42	-
Investment funds								
Mutual funds—equity	-	145	-	-	-	-	-	145
Pooled funds—equity	-	-	930	103	-	-	930	103
Pooled funds—fixed income			327	99			327	99
Real estate	-	-	-	-	36	-	36	-
Other[(a)]	-	-	92	-	23	-	115	-
Total investments, at fair value	$ 59	$ 146	$ 1,463	$ 202	$ 101	$ -	$ 1,623	$ 348

(a) Includes an $86 million receivable for the sale of an investment that closed as of December 31, 2009 but did not cash settle until the next business day.

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

(In millions)	Private Equity	Real Estate	Other	Total
Balance as of December 31, 2008	$ 35	$ 51	$ 7	$ 93
Actual Return on plan assets held at December 31, 2009	2	(21)	1	(18)
Purchases, sales and settlements, net	5	6	15	26
Balance as of December 31, 2009	$ 42	$ 36	$ 23	$ 101

Cash flows

Contributions to defined benefit plans – We expect to make contributions to the funded pension plans of up to $17 million in 2010. Cash contributions to be paid from our general assets for the unfunded pension and postretirement plans are expected to be approximately $18 million and $39 million in 2010.

Estimated future benefit payments – The following gross benefit payments, which reflect expected future service, as appropriate, are expected to be paid in the years indicated.

	Pension Benefits		Other
(In millions)	U.S.	Int'l	Benefits[a]
2010	$ 208	$ 10	$ 39
2011	225	11	42
2012	247	12	44
2013	260	12	47
2014	272	15	50
2015 through 2019	1,489	102	288

(a) Expected Medicare reimbursements for 2010 through 2019 total $54 million.

Contributions to defined contribution plans – We also contribute to several defined contribution plans for eligible employees. Contributions to these plans totaled $59 million in 2009, $49 million in 2008 and $55 million in 2007.

23. Stock-Based Compensation Plans

Description of the Plans

The Marathon Oil Corporation 2007 Incentive Compensation Plan (the "2007 Plan") was approved by our stockholders in April 2007 and authorizes the Compensation Committee of the Board of Directors to grant stock options, stock appreciation rights, stock awards (including restricted stock and restricted stock unit awards) and performance awards to employees. The 2007 Plan also allows us to provide equity compensation to our non-employee directors. No more than 34 million shares of Marathon common stock may be issued under the 2007 Plan and no more than 12 million of those shares may be used for awards other than stock options or stock appreciation rights.

Shares subject to awards under the 2007 Plan that are forfeited, are terminated or expire unexercised become available for future grants. If a stock appreciation right is settled upon exercise by delivery of shares of common stock, the full number of shares with respect to which the stock appreciation right was exercised will count against the number of shares of Marathon common stock reserved for issuance under the 2007 Plan and will not again become available under the 2007 Plan. In addition, the number of shares of Marathon common stock reserved for issuance under the 2007 Plan will not be increased by shares tendered to satisfy the purchase price of an award, exchanged for other awards or withheld to satisfy tax withholding obligations. Shares issued as a result of awards granted under the 2007 Plan are generally funded out of common stock held in treasury, except to the extent there are insufficient treasury shares, in which case new common shares are issued.

After approval of the 2007 Plan, no new grants were or will be made from the 2003 Incentive Compensation Plan (the "2003 Plan"). The 2003 Plan replaced the 1990 Stock Plan, the Non-Officer Restricted Stock Plan, the Non-Employee Director Stock Plan, the deferred stock benefit provision of the Deferred Compensation Plan for Non-Employee Directors, the Senior Executive Officer Annual Incentive Compensation Plan and the Annual Incentive Compensation Plan (the "Prior Plans"). No new grants will be made from the Prior Plans. Any awards previously granted under the 2003 Plan or the Prior Plans shall continue to vest or be exercisable in accordance with their original terms and conditions.

Stock-based awards under the Plan

Stock options – We grant stock options under the 2007 Plan. Our stock options represent the right to purchase shares of Marathon common stock at its fair market value on the date of grant. Through 2004, certain stock options were granted under the 2003 Plan with a tandem stock appreciation right, which allows the recipient to instead elect to receive cash or Marathon common stock equal to the excess of the fair market value of shares of common stock, as determined in accordance with the 2003 Plan, over the option price of the shares. In general, stock options granted under the 2007 Plan and the 2003 Plan vest ratably over a three-year period and have a maximum term of ten years from the date they are granted.

Stock appreciation rights – Prior to 2005, we granted SARs under the 2003 Plan. No stock appreciation rights have been granted under the 2007 Plan. Similar to stock options, stock appreciation rights represent the right to receive a payment equal to the excess of the fair market value of shares of common stock on the date the right is exercised over the grant price. Under the 2003 Plan, certain SARs were granted as stock-settled SARs and others were granted in tandem with stock options. In general, SARs granted under the 2003 Plan vest ratably over a three-year period and have a maximum term of ten years from the date they are granted.

Stock-based performance awards – Prior to 2005, we granted stock-based performance awards under the 2003 Plan. No stock-based performance awards have been granted under the 2007 Plan. Beginning in 2005, we discontinued granting stock-based performance awards and instead now grant cash-settled performance units to officers. All stock-based performance awards granted under the 2003 Plan have either vested or been forfeited. As a result, there are no outstanding stock-based performance awards.

Restricted stock – We grant restricted stock and restricted stock units under the 2007 Plan and previously granted such awards under the 2003 Plan. In 2005, the Compensation Committee began granting time-based restricted stock to certain U.S.-based officers of Marathon and its consolidated subsidiaries as part of their annual long-term incentive package. The restricted stock awards to officers vest three years from the date of grant, contingent on the recipient's continued employment. We also grant restricted stock to certain non-officer employees and restricted stock units to certain international employees ("restricted stock awards"), based on their performance within certain guidelines and for retention purposes. The restricted stock awards to non-officers generally vest in one-third increments over a three-year period, contingent on the recipient's continued employment, however, certain restricted stock awards granted in 2008 will vest over a four-year period, contingent on the recipient's continued employment. Prior to vesting, all restricted stock recipients have the right to vote such stock and receive dividends thereon. The non-vested shares are not transferable and are held by our transfer agent.

Common stock units – We maintain an equity compensation program for our non-employee directors under the 2007 Plan and previously maintained such a program under the 2003 Plan. All non-employee directors other than the Chairman receive annual grants of common stock units, and they are required to hold those units until they leave the Board of Directors. When dividends are paid on Marathon common stock, directors receive dividend equivalents in the form of additional common stock units.

Total stock-based compensation expense

Total employee stock-based compensation expense was $76 million, $43 million and $66 million in 2009, 2008 and 2007, while the total related income tax benefits were $29 million, $16 million and $24 million in the same years. In 2009, 2008 and 2007 cash received upon exercise of stock option awards was $4 million, $9 million and $27 million. Tax benefits realized for deductions for stock awards exercised during 2009, 2008 and 2007 during the period totaled $1 million, $4 million and $24 million. Cash settlements of stock option awards totaled $1 million in 2007. There were no cash settlements in 2009 or 2008.

Stock option awards

During 2009, 2008 and 2007, we granted stock option awards to both officer and non-officer employees. The weighted average grant date fair value of these awards was based on the following Black-Scholes assumptions:

	2009	2008	2007
Weighted average exercise price per share	$ 27.62	$ 51.74	$ 60.94
Expected annual dividends per share	0.96	0.96	0.96
Expected life in years	4.9	4.8	5.0
Expected volatility	41%	30%	27%
Risk-free interest rate	2.3%	3.1%	4.1%
Weighted average grant date fair value of stock option awards granted	$ 7.67	$ 13.03	$ 17.24

The following is a summary of stock option award activity in 2009.

	Number of Shares	Weighted - Average Exercise price
Outstanding at December 31, 2008	13,841,748	$ 37.59
Granted	4,970,500	27.62
Exercised	(273,382)	15.89
Cancelled	(308,792)	45.27
Outstanding at December 31, 2009	18,230,074	$ 35.01

The intrinsic value of stock option awards exercised during 2009, 2008 and 2007 was $3 million, $12 million and $64 million. Of those amounts, $1 million in 2009 and $10 million in 2007 related to stock options with tandem SARs. No stock options with tandem SARs were exercised in 2008.

The following table presents information related to stock option awards at December 31, 2009.

	Outstanding			Exercisable	
Range of Exercise Prices	Number of Shares Under Option	Weighted - Average Remaining Contractual Life	Weighted-Average Exercise Price	Number of Shares Under Option	Weighted-Average Exercise Price
$ 12.75-16.81	3,179,480	4	$ 15.56	3,179,480	$ 15.56
23.21-29.24	7,242,984	8	26.77	2,445,856	24.90
37.82-47.91	2,646,100	6	38.12	2,581,774	37.94
51.17-61.33	5,161,510	7	56.98	2,764,456	58.38
Total	18,230,074	7	35.01	10,971,566	33.70

As of December 31, 2009, the aggregate intrinsic value of stock option awards outstanding was $82 million. The aggregate intrinsic value and weighted average remaining contractual life of stock option awards currently exercisable were $65 million and 5 years.

As of December 31, 2009, the number of fully-vested stock option awards and stock option awards expected to vest was 18,047,400. The weighted average exercise price and weighted average remaining contractual life of these stock option awards were $35.02 and 7 years and the aggregate intrinsic value was $82 million. As of December 31, 2009, unrecognized compensation cost related to stock option awards was $42 million, which is expected to be recognized over a weighted average period of 2 years.

Restricted stock awards

The following is a summary of restricted stock award activity.

	Awards	Weighted-Average Grant Date Fair Value
Unvested at December 31, 2008	2,049,255	$47.72
Granted	251,335	24.74
Vested	(762,466)	46.03
Forfeited	(96,625)	43.56
Unvested at December 31, 2009	1,441,499	44.89

The vesting date fair value of restricted stock awards which vested during 2009, 2008 and 2007 was $24 million, $38 million and $29 million. The weighted average grant date fair value of restricted stock awards was $44.89, $47.72, and $39.87 for awards unvested at December 31, 2009, 2008 and 2007.

As of December 31, 2009, there was $43 million of unrecognized compensation cost related to restricted stock awards which is expected to be recognized over a weighted average period of 1.6 years.

Stock-based performance awards

All stock-based performance awards have either vested or been forfeited. The vesting date fair value of stock-based performance awards which vested during 2007 was $38.

24. Stockholders' Equity

In each year, 2009 and 2008, we issued 2 million in common stock upon the redemption of the Exchangeable Shares described below in addition to treasury shares issued for employee stock-based awards.

The Board of Directors has authorized the repurchase of up to $5 billion of Marathon common stock. Purchases under the program may be in either open market transactions, including block purchases, or in privately negotiated transactions. We will use cash on hand, cash generated from operations, proceeds from potential asset sales or cash from available borrowings to acquire shares. This program may be changed based upon our financial condition or changes in market conditions and is subject to termination prior to completion. The repurchase program does not include specific price targets or timetables. As of December 31, 2009, we have acquired 66 million common shares at a cost of $2,922 million under the program. No shares have been acquired since August 2008.

Securities exchangeable into Marathon common stock – As discussed in Note 6, we acquired all of the outstanding shares of Western on October 18, 2007. The Western shareholders who were Canadian residents received, at their election, cash, Marathon common stock, securities exchangeable into Marathon common stock (the "Exchangeable Shares") or a combination thereof. The Western shareholders elected to receive 5 million Exchangeable Shares as part of the acquisition consideration. The Exchangeable Shares are shares of an indirect Canadian subsidiary of Marathon and, at the acquisition date, were exchangeable on a one-for-one basis into Marathon common stock. Subsequent to the acquisition, the exchange ratio is adjusted to reflect cash dividends, if any, paid on Marathon common stock and cash dividends, if any, paid on the Exchangeable Shares. The exchange ratio at December 31, 2009, was 1.06109 common shares for each Exchangeable Share. The Exchangeable Shares are exchangeable at the option of the holder at any time and are automatically redeemable on October 18, 2011.

Holders of Exchangeable Shares are entitled to instruct a trustee to vote (or obtain a proxy from the trustee to vote directly) on all matters submitted to the holders of Marathon common stock. The number of votes to which each holder is entitled is equal to the whole number of shares of Marathon common stock into which such holder's Exchangeable Shares would be exchangeable based on the exchange ratio in effect on the record date for the vote. The voting right is attached to voting preferred shares of Marathon that were issued to a trustee in an amount equivalent to the Exchangeable Shares at the acquisition date as discussed below. Additional shares of voting preferred stock will be issued as necessary to adjust the number of votes to account for changes in the exchange ratio.

Preferred shares – In connection with the acquisition of Western discussed in Note 6, the Board of Directors authorized a class of voting preferred stock consisting of 6 million shares. Upon completion of the acquisition, we issued 5 million shares of this voting preferred stock to a trustee, who holds the shares for the benefit of the holders of the Exchangeable Shares discussed above. Each share of voting preferred stock is entitled to one vote on all matters submitted to the holders of Marathon common stock. Each holder of Exchangeable Shares may direct the trustee to vote the number of shares of voting preferred stock equal to the number of shares of Marathon common stock issuable upon the exchange of the Exchangeable Shares held by that holder. In no event will the aggregate number of votes entitled to be cast by the trustee with respect to the outstanding shares of voting preferred stock exceed the number of votes entitled to be cast with respect to the outstanding Exchangeable Shares. Except as otherwise provided in our restated certificate of incorporation or by applicable law, the common stock and the voting preferred stock will vote together as a single class in the election of directors of Marathon and on all other matters submitted to a vote of stockholders of Marathon generally. The voting preferred stock will have no other voting rights except as required by law. Other than dividends payable solely in shares of voting preferred stock, no dividend or other distribution, will be paid or payable to the holder of the voting preferred stock. In the event of any liquidation, dissolution or winding up of Marathon, the holder of shares of the voting preferred stock will not be entitled to receive any assets of Marathon available for distribution to its stockholders. The voting preferred stock is not convertible into any other class or series of the capital stock of Marathon or into cash, property or other rights, and may not be redeemed.

25. Leases

We lease a wide variety of facilities and equipment under operating leases, including land and building space, office equipment, production facilities and transportation equipment. Most long-term leases include renewal options and, in certain leases, purchase options. Future minimum commitments for capital lease obligations (including sale-leasebacks accounted for as financings) and for operating lease obligations having initial or remaining noncancelable lease terms in excess of one year are as follows:

(In millions)	Capital Lease Obligations[(a)]	Operating Lease Obligations
2010	$ 46	$ 165
2011	45	140
2012	58	121
2013	44	102
2014	44	84
Later years	466	313
Sublease rentals	-	(16)
Total minimum lease payments	$ 703	$ 909
Less imputed interest costs	(257)	
Present value of net minimum lease payments	$ 446	

(a) Capital lease obligations include $164 million related to assets under construction as of December 31, 2009. These leases are currently reported in long-term debt based on percentage of construction completed at $36 million.

In connection with past sales of various plants and operations, we assigned and the purchasers assumed certain leases of major equipment used in the divested plants and operations of United States Steel. In the event of a default by any of the purchasers, United States Steel has assumed these obligations; however, we remain primarily obligated for payments under these leases. Minimum lease payments under these operating lease obligations of $16 million have been included above and an equal amount has been reported as sublease rentals.

Of the $446 million present value of net minimum capital lease payments, $53 million was related to obligations assumed by United States Steel under the Financial Matters Agreement.

Operating lease rental expense was:

(In millions)	2009	2008	2007
Minimum rental[a]	$ 238	$ 245	$ 209
Contingent rental	19	22	33
Net rental expense	$ 257	$ 267	$ 242

[a] Excludes $3 million, $5 million and $8 million paid by United States Steel in 2009, 2008 and 2007 on assumed leases.

26. 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. Certain of these matters are discussed below. 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.

Environmental matters – We are subject to federal, state, local and foreign laws and regulations relating to the environment. These laws generally provide for control of pollutants released into the environment and require responsible parties to undertake remediation of hazardous waste disposal sites. Penalties may be imposed for noncompliance. At December 31, 2009 and 2008, accrued liabilities for remediation totaled $116 million and $111 million. It is not presently possible to estimate the ultimate amount of all remediation costs that might be incurred or the penalties that may be imposed. Receivables for recoverable costs from certain states, under programs to assist companies in clean-up efforts related to underground storage tanks at retail marketing outlets, were $59 and $60 million at December 31, 2009 and 2008.

Legal cases – We, along with other refining companies, 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 27 cases arising in four states alleging damages for MTBE contamination. Like the cases that we settled in 2008, 12 of the remaining cases are consolidated in a multi-district litigation ("MDL") in the Southern District of New York for pretrial proceedings. The other 15 cases are in New York state courts (Nassau and Suffolk Counties). Plaintiffs in 26 of the 27 cases allege damages to water supply wells from contamination of groundwater by MTBE, similar to the damages claimed in the cases settled in 2008. In the remaining case, the New Jersey Department of Environmental Protection is seeking the cost of remediating MTBE contamination and natural resources damages allegedly resulting from contamination of groundwater by MTBE. We are vigorously defending these cases. We have engaged in settlement discussions related to the majority of these cases. We do not expect our share of liability for these 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 to one qui tam case, which alleges that Marathon and other defendants violated the False Claims Act with respect to the reporting and payment of royalties on natural gas and natural gas liquids for federal and Indian leases. A qui tam action is an action in which the relator files suit on behalf of himself as well as the federal government. The case currently pending is U.S. ex rel Harrold E. Wright v. Agip Petroleum Co. et al. It is primarily a gas valuation case. Marathon has reached a settlement with the Relator and the DOJ which will be finalized after the Indian Tribes review and approve the settlement terms. Such settlement is not expected to significantly impact our consolidated results of operations, financial position or cash flows.

Guarantees – We have provided certain guarantees, direct and indirect, of the indebtedness of other companies. Under the terms of most of these guarantee arrangements, we would be required to perform should the guaranteed party fail to fulfill its obligations under the specified arrangements. In addition to these financial guarantees, we also have various performance guarantees related to specific agreements.

Guarantees related to indebtedness of equity method investees – We hold interests in an offshore oil port, LOOP LLC, and a crude oil pipeline system, LOCAP LLC. Both LOOP LLC and LOCAP LLC have secured various project financings with throughput and deficiency agreements. Under the agreements, we are required to advance funds if the investees are unable to service their debt. Any such advances are considered prepayments of future transportation charges. The terms of the agreements vary but tend to follow the terms of the underlying debt. Our maximum potential undiscounted payments under these agreements totaled $172 million as of December 31, 2009.

We hold an interest in a refined products pipeline through our investment in Centennial, and have guaranteed the repayment of Centennial's outstanding balance under a Master Shelf Agreement which expires in 2024. The guarantee arose in order for Centennial to obtain adequate financing. Our maximum potential undiscounted payments under this agreement totaled $60 million as of December 31, 2009.

Other guarantees – We have entered into other guarantees with maximum potential undiscounted payments totaling $190 million as of December 31, 2009, which consist primarily of leases of corporate assets containing general lease indemnities and guaranteed residual values, a commitment to contribute cash to an equity method investee for certain catastrophic events in lieu of procuring insurance coverage, a legal indemnification, a performance guarantee and a long-term transportation services agreement.

United States Steel was the sole general partner of Clairton 1314B Partnership, L.P., which owned certain cokemaking facilities formerly owned by United States Steel. We have agreed, under certain circumstances, to indemnify the limited partners if the partnership's product sales fail to qualify for the credit under Section 29 of the Internal Revenue Code. The Clairton 1314B Partnership was terminated on October 31, 2008, but we were not released from our obligations. United States Steel has estimated the maximum potential amount of this indemnity obligation, including interest and tax gross-up, was approximately $100 million as of December 31, 2009.

General guarantees associated with dispositions – Over the years, we have sold various assets in the normal course of our business. Certain of the related agreements contain performance and general guarantees, including guarantees regarding inaccuracies in representations, warranties, covenants and agreements, and environmental and general indemnifications that require us to perform upon the occurrence of a triggering event or condition. These guarantees and indemnifications are part of the normal course of selling assets. We are typically not able to calculate the maximum potential amount of future payments that could be made under such contractual provisions because of the variability inherent in the guarantees and indemnities. Most often, the nature of the guarantees and indemnities is such that there is no appropriate method for quantifying the exposure because the underlying triggering event has little or no past experience upon which a reasonable prediction of the outcome can be based.

Existing guarantees of our subsidiaries' performance issued to Irish government entities will remain in place after the 2009 sales until the purchasers issue similar guarantees to replace them. The guarantees, related to asset retirement obligations and natural gas production levels, have been indemnified by the purchasers. Our maximum potential undiscounted payments under these guarantees as of December 31, 2009 are $157 million.

Contract commitments – At December 31, 2009 and 2008, our contract commitments to acquire property, plant and equipment totaled $ 2,938 million and $4,070 million.

Other contingencies – In November 2006, the government of Equatorial Guinea enacted a new hydrocarbon law governing petroleum operations in Equatorial Guinea. The transitional provision of the law provides that all contractors and the terms of any contract to which they are a party will be subject to the law. The governmental agency responsible for the energy industry was given the authority to renegotiate any contract for the purpose of adapting any terms and conditions that are inconsistent with the new law. We are in the process of determining what impact this law may have on our existing operations in Equatorial Guinea.

Selected Quarterly Financial Data (Unaudited)

	2009				2008			
(In millions, except per share data)[(a)]	1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.	1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.[(b)]
Revenues	$ 10,176	$ 13,039	$ 14,362	$ 15,893	$ 17,648	$ 21,889	$ 22,969	$ 14,248
Income from operations	538	1,042	1,017	993	1,198	1,593	3,639	349
Income (loss) from continuing operations	265	328	392	199	680	761	1,992	(49)
Discontinued operations	17	85	21	156	51	13	72	8
Net income (loss)	282	413	413	355	731	774	2,064	(41)
Net income (loss) per share:								
- Basic	$ 0.40	$ 0.58	$ 0.58	$ 0.50	$ 1.03	$ 1.09	$ 2.92	$ (0.06)
- Diluted	$ 0.40	$ 0.58	$ 0.58	$ 0.50	$ 1.02	$ 1.08	$ 2.90	$ (0.06)
Dividends paid per share	$ 0.24	$ 0.24	$ 0.24	$ 0.24	$ 0.24	$ 0.24	$ 0.24	$ 0.24

(a) Our businesses in Ireland and Gabon were sold in 2009. All periods have been recast to reflect these businesses in discontinued operations.

(b) Reflects a $1,412 million impairment of goodwill related to the OSM segment. See Note 15 to the consolidated financial statements.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

The supplementary information is disclosed by the following geographic areas: the United States; Europe, which primarily includes activities in the United Kingdom and Norway; Equatorial Guinea ("EG"); Other Africa, which primarily includes activities in Angola and Libya; Canada; and Other International ("Other Int'l"), which primarily includes activities in Indonesia. Discontinued operations ("Disc Ops") represent Marathon's Irish and Gabonese oil exploration and production businesses that were sold in 2009.

Estimated Quantities of Proved Oil and Gas Reserves

In December 2008, the Securities and Exchange Commission ("SEC") announced revisions to its regulations on oil and gas reporting. In January 2010, the Financial Accounting Standards Board issued an accounting standards update which was intended to harmonize the accounting literature with the SEC's new regulations. See Item 8. Financial Statements and Supplementary Data – Note 2 for a summary of the changes. The revised regulations were applied in estimating and reporting our reserves as of December 31, 2009.

The estimation of net recoverable quantities of liquid hydrocarbons, natural gas and synthetic crude oil is a highly technical process, which is based upon several underlying assumptions that are subject to change. For a discussion of our reserve estimation process, including the use of third-party audits, see Item 1 – Business.

(Millions of barrels)	United States	Canada[a]	EG[b]	Other Africa	Europe	Continuing Operations	Disc Ops
Liquid Hydrocarbons							
Proved developed and undeveloped reserves:							
Beginning of year - 2007	172	-	177	210	108	667	10
Revisions of previous estimates	2	-	(10)	-	7	(1)	2
Improved recovery	8	-	-	-	-	8	-
Purchase of reserves in place	2	-	-	-	-	2	-
Extensions, discoveries and other additions	5	-	-	16	13	34	-
Production[b]	(23)	-	(17)	(16)	(13)	(69)	(3)
End of year - 2007	166	-	150	210	115	641	9
Revisions of previous estimates	3	-	4	7	(1)	13	(3)
Improved recovery	1	-	-	-	-	1	-
Extensions, discoveries and other additions	31	-	-	11	11	53	-
Production[b]	(23)	-	(15)	(17)	(20)	(75)	(2)
Sales of reserves in place	-	-	-	-	(1)	(1)	-
End of year - 2008	178	-	139	211	104	632	4
Revisions of previous estimates	-	-	(2)	3	19	20	2
Extensions, discoveries and other additions	21	-	-	31	12	64	-
Production[b]	(23)	-	(15)	(17)	(33)	(88)	(2)
Sales of reserves in place	(6)	-	-	-	-	(6)	(4)
End of year - 2009	170	-	122	228	102	622	-
Proved developed reserves:							
Beginning of year - 2007	150	-	176	196	35	557	9
End of year - 2007	135	-	113	183	32	463	8
End of year - 2008	137	-	99	193	81	510	4
End of year - 2009	120	-	83	186	87	476	-
Proved undeveloped reserves:							
Beginning of year - 2007	22	-	1	14	73	110	1
End of year - 2007	31	-	37	27	83	178	1
End of year - 2008	41	-	40	18	23	122	-
End of year - 2009	50	-	39	42	15	146	-

Estimated Quantities of Proved Oil and Gas Reserves (continued)

	United States	Canada[a]	EG[b]	Other Africa	Europe	Continuing Operations	Disc Ops
Natural Gas *(billions of cubic feet)*							
Proved developed and undeveloped reserves:							
Beginning of year - 2007	1,069	-	1,974	23	293	3,359	151
Revisions of previous estimates	(36)	-	60	-	(11)	13	6
Purchase of reserves in place	1	-	-	-	-	1	-
Extensions, discoveries and other additions	148	-	-	88	4	240	-
Production[c]	(174)	-	(83)	(1)	(48)	(306)	(13)
Sales of reserves in place	(1)	-	-	-	-	(1)	-
End of year - 2007	1,007	-	1,951	110	238	3,306	144
Revisions of previous estimates	79	-	49	-	(51)	77	-
Extensions, discoveries and other additions	165	-	-	-	30	195	-
Production[c]	(164)	-	(134)	(1)	(48)	(347)	(12)
Sales of reserves in place	(2)	-	-	-	(10)	(12)	-
End of year - 2008	1,085	-	1,866	109	159	3,219	132
Revisions of previous estimates	(139)	-	(23)	-	(10)	(172)	-
Extensions, discoveries and other additions	80	-	-	-	2	82	-
Production[c]	(146)	-	(155)	(2)	(42)	(345)	(6)
Sales of reserves in place	(60)	-	-	-	-	(60)	(126)
End of year - 2009	820	-	1,688	107	109	2,724	-
Proved developed reserves:							
Beginning of year - 2007	857	-	625	23	185	1,690	53
End of year - 2007	761	-	1,405	110	127	2,403	46
End of year - 2008	839	-	1,273	109	95	2,316	34
End of year - 2009	652	-	1,102	107	50	1,911	-
Proved undeveloped reserves:							
Beginning of year - 2007	212	-	1,349	-	108	1,669	98
End of year - 2007	246	-	546	-	111	903	98
End of year - 2008	246	-	593	-	64	903	98
End of year - 2009	168	-	586	-	59	813	-
Synthetic crude oil *(millions of barrels)*							
Proved developed and undeveloped reserves:							
Beginning of year - 2009	-	-	-	-	-	-	-
Revisions of previous estimates	-	603	-	-	-	603	-
End of year - 2009	-	603	-	-	-	603	-
Proved developed reserves:							
Beginning of year - 2009	-	-	-	-	-	-	-
End of year - 2009	-	392	-	-	-	392	-
Proved undeveloped reserves:							
Beginning of year - 2009	-	-	-	-	-	-	-
End of year - 2009	-	211	-	-	-	211	-

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Estimated Quantities of Proved Oil and Gas Reserves (continued)

(millions of barrels of oil equivalent)	United States	Canada[a]	EG[b]	Other Africa	Europe	Continuing Operations	Disc Ops
Total Proved Reserves							
Proved developed and undeveloped reserves:							
Beginning of year - 2007	350	-	506	214	157	1,227	35
Revisions of previous estimates	(4)	-	-	-	5	1	3
Improved recovery	8	-	-	-	-	8	-
Purchase of reserves in place	2	-	-	-	-	2	-
Extensions, discoveries and other additions	30	-	-	31	13	74	-
Production[c]	(52)	-	(31)	(17)	(20)	(120)	(5)
End of year - 2007	334	-	475	228	155	1,192	33
Revisions of previous estimates	15	-	12	7	(9)	25	(2)
Improved recovery	1	-	-	-	-	1	-
Extensions, discoveries and other additions	59	-	-	11	16	86	-
Production[c]	(50)	-	(37)	(17)	(28)	(132)	(5)
Sales of reserves in place	-	-	-	-	(3)	(3)	-
End of year - 2008	359	-	450	229	131	1,169	26
Revisions of previous estimates[d]	(22)	603	(6)	3	17	595	1
Extensions, discoveries and other additions	34	-	-	31	13	78	-
Production[c]	(48)	-	(41)	(17)	(41)	(147)	(2)
Sales of reserves in place	(16)	-	-	-	-	(16)	(25)
End of year-2009	307	603	403	246	120	1,679	-
Proved developed reserves:							
Beginning of year - 2007	293	-	280	200	66	839	18
End of year - 2007	262	-	347	202	52	863	16
End of year - 2008	277	-	312	211	96	896	10
End of year - 2009	229	392	267	204	95	1,187	-
Proved undeveloped reserves:							
Beginning of year-2007	57	-	226	14	91	388	17
End of year - 2007	72	-	128	26	103	329	17
End of year - 2008	82	-	138	18	35	273	16
End of year - 2009	78	211	136	42	25	492	-

(a) Synthetic crude oil proved reserves were added as of December 31, 2009.
(b) Consists of estimated reserves from properties governed by production sharing contracts.
(c) Excludes the resale of purchased natural gas utilized in reservoir management.
(d) Volumes for Canada are after 10 million barrels of synthetic crude oil production in 2009.

The most significant impact of adopting the SEC's new regulations on oil and gas producing activities was the addition of 603 mmbbl of synthetic crude oil to our reserves in 2009. Other changes resulting from the new regulations did not have a significant impact.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Information on Proved Bitumen Reserves

We previously reported reserves related to our oil sands mining operations in Alberta, Canada, as bitumen, which were reported separately from other reserves since bitumen reserves were not considered related to oil and gas producing activities by the SEC. Reserve quantities under the new regulations include synthetic crude oil (bitumen after upgrading) reserves and are included in the Estimated Quantities of Proved Oil and Gas Reserves for 2009. During 2009, activity related to our bitumen reserves included purchase of reserves of 168 million barrels ("mmbbl") of bitumen and production of 9 mmbbl of bitumen.

(Millions of barrels)	Continuing Operations
Proved Bitumen Reserves:	
Beginning of year - 2007	-
Purchase of reserves in place	420
Revisions	2
Production	(1)
End of year - 2007	421
Revisions	(30)
Extensions, discoveries and other additions	6
Production	(9)
End of year - 2008	388

Capitalized Costs and Accumulated Depreciation, Depletion and Amortization

(In millions)	United States	Canada[(a)]	EG	Other Africa	Europe	Other Int'l	Total
	December 31,						
2009 Capitalized costs:							
Proved properties	$ 10,927	$ 7,510	$ 1,521	$ 1,505	$ 7,790	$ 3	$ 29,256
Unproved properties	1,258	1,544	24	404	68	19	3,317
Total	12,185	9,054	1,545	1,909	7,858	22	32,573
Accumulated depreciation, depletion and amortization:							
Proved properties	6,128	280	516	85	5,230	1	12,240
Unproved properties	60	-	-	9	1	8	78
Total	6,188	280	516	94	5,231	9	12,318
Net capitalized costs	$ 5,997	$ 8,774	$ 1,029	$ 1,815	$ 2,627	$ 13	$ 20,255
2008 Capitalized costs:							
Proved properties	$ 10,008	$ -	$ 1,455	$ 802	$ 8,460	$ 1	$ 20,726
Unproved properties	1,543	315	53	976	109	19	3,015
Total	11,551	315	1,508	1,778	8,569	20	23,741
Accumulated depreciation, depletion and amortization:							
Proved properties	5,927	-	401	226	4,995	1	11,550
Unproved properties	69	-	-	9	1	8	87
Total	5,996	-	401	235	4,996	9	11,637
Net capitalized costs	$ 5,555	$ 315	$ 1,107	$ 1,543	$ 3,573	$ 11	$ 12,104

(a) 2009 includes amounts related to our oil sands mining operations.

Costs Incurred for Property Acquisition, Exploration and Development [(a)]

(In millions)	United States	Canada[(b)]	EG	Other Africa	Europe	Other Int'l	Continuing Operations	Disc Ops	Total
2009 Property acquisition:									
Proved	$ -	$ 11	$ -	$ -	$ -	$ -	$ 11	$ 15	$ 26
Unproved	127	1	-	6	-	2	136	-	136
Exploration	271	11	-	127	81	29	519	-	519
Development	1,150	976	23	266	354	-	2,769	64	2,833
Total	$1,548	$999	$23	$399	$435	$31	$3,435	$ 79	$3,514
2008 Property acquisition:									
Proved	$ 3	$ -	$ -	$ -	$ -	$ -	$ 3	$ -	$ 3
Unproved	397	-	-	8	-	7	412	-	412
Exploration	738	31	1	155	56	85	1,066	1	1,067
Development	1,072	-	30	141	516	-	1,759	165	1,924
Total	$2,210	$ 31	$31	$304	$572	$92	$3,240	$166	$3,406
2007 Property acquisition:									
Proved	$ 4	$ -	$ -	$ -	$ -	$ -	$ 4	$ -	$ 4
Unproved	142	309	-	1	1	6	459	-	459
Exploration	523	4	1	218	68	40	854	-	854
Development	697	-	21	72	754	-	1,544	114	1,658
Total	$1,366	$313	$22	$291	$823	$46	$2,861	$114	$2,975

(a) Includes costs incurred whether capitalized or expensed.
(b) 2009 includes amounts related to our oil sands mining operations.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Results of Operations for Oil and Gas Producing Activities

(In millions)	United States	Canada[(a)]	EG	Other Africa	Europe	Other Int'l	Total
2009 Revenues and other income:							
Sales[(b)]	$ 1,426	$ 499	$ 23	$ 1,146	$ 699	$ -	$ 3,793
Transfers	437	100	587	-	1,678	-	2,802
Other income[(c)]	185	-	-	-	13	-	198
Total revenues and other income	2,048	599	610	1,146	2,390	-	6,793
Expenses:							
Production costs	(763)	(371)	(108)	(62)	(289)	-	(1,593)
Exploration expenses	(153)	(16)	-	(73)	(37)	(28)	(307)
Depreciation, depletion and amortization	(846)	(126)	(115)	(37)	(736)	-	(1,860)
Administrative expenses	(53)	(9)	(1)	(3)	(13)	(22)	(101)
Total expenses	(1,815)	(522)	(224)	(175)	(1,075)	(50)	(3,861)
Results before income taxes	233	77	386	971	1,315	(50)	2,932
Income tax (provision) benefit	(76)	(17)	(112)	(770)	(678)	14	(1,639)
Results of continuing operations	$ 157	$ 60	$ 274	$ 201	$ 637	$ (36)	$ 1,293
Results of discontinued operations	$ -	$ -	$ -	$ 194	$ 79	$ -	$ 273
2008 Revenues and other income:							
Sales[(b)]	$ 2,619	$ -	$ 28	$ 1,858	$ 1,164	$ -	$ 5,669
Transfers	547	-	995	-	1,062	-	2,604
Other income[(c)]	1	-	-	-	254	-	255
Total revenues and other income	3,167	-	1,023	1,858	2,480	-	8,528
Expenses:							
Production costs	(845)	-	(96)	(41)	(340)	-	(1,322)
Exploration expenses	(238)	(25)	(2)	(45)	(87)	(92)	(489)
Depreciation, depletion and amortization	(671)	-	(102)	(35)	(475)	(1)	(1,284)
Administrative expenses	(49)	(1)	(1)	(15)	(16)	(36)	(118)
Total expenses	(1,803)	(26)	(201)	(136)	(918)	(129)	(3,213)
Results before income taxes	1,364	(26)	822	1,722	1,562	(129)	5,315
Income tax (provision) benefit	(513)	6	(280)	(1,550)	(551)	44	(2,844)
Results of continuing operations	$ 851	$ (20)	$ 542	$ 172	$ 1,011	$ (85)	$ 2,471
Results of discontinued operations	$ -	$ -	$ -	$ 117	$ 28	$ -	$ 145
2007 Revenues and other income:							
Sales[(b)]	$ 2,110	$ -	$ 10	$ 1,319	$ 1,111	$ -	$ 4,550
Transfers	299	-	821	-	60	-	1,180
Other income[(c)]	3	-	2	-	-	7	12
Total revenues and other income	2,412	-	833	1,319	1,171	7	5,742
Expenses:							
Production costs	(672)	-	(95)	(60)	(228)	-	(1,055)
Exploration expenses	(274)	(3)	(1)	(117)	(23)	(34)	(452)
Depreciation, depletion and amortization	(486)	-	(87)	(31)	(243)	-	(847)
Administrative expenses	(56)	-	(3)	(2)	(10)	(34)	(105)
Total expenses	(1,488)	(3)	(186)	(210)	(504)	(68)	(2,459)
Results before income taxes	924	(3)	647	1,109	667	(61)	3,283
Income tax (provision) benefit	(343)	-	(228)	(1,061)	(330)	22	(1,940)
Results of continuing operations	$ 581	$ (3)	$ 419	$ 48	$ 337	$ (39)	$ 1,343
Results of discontinued operations	$ -	$ -	$ -	$ 114	$ 4	$ 8	$ 126

(a) 2009 includes amounts related to our oil sands mining operations.
(b) Excludes noncash effects of changes in the fair value of certain natural gas sales contracts in the United Kingdom.
(c) Includes net gain on disposal of assets.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Results of Operations for Oil and Gas Producing Activities

The following reconciles results of continuing operations for oil and gas producing activities to segment income:

(In millions)	2009	2008	2007
Results of continuing operations	$ 1,293	$ 2,471	$ 1,343
Items not included in results of continuing oil and gas operations, net of tax:			
Marketing income and technology costs	(21)	27	31
Income from equity method investments	110	201	154
Other third-party income[(a)]	9	26	30
Other	(4)	(6)	(6)
Items not allocated to segment income:			
Gain on asset disposition	(122)	(163)	-
Segment income (loss) not included in results of continuing oil and gas operations:			
Oil Sands Mining[(b)]	N/A	258	(63)
Refining, Marketing and Transportation	464	1,179	2,077
Integrated Gas	90	302	132
Segment income	$ 1,819	$ 4,295	$ 3,698

(a) Includes revenues, net of associated costs and income taxes, from activities that support our production operations, which may include processing or transportation of third-party production and the purchase and subsequent resale of natural gas utilized for reservoir management.

(b) 2009 Oil Sands Mining segment income is included in the Results of Operations for Oil and Gas Producing Activities.

Standardized Measure of Discounted Future Net Cash Flows

	December 31,					
(In millions)	United States	Canada	EG	Other Africa	Europe	Total
2009						
Future cash inflows	$ 12,094	$ 32,207	$ 4,620	$ 14,974	$ 6,901	$ 70,796
Future production and administrative costs	(6,796)	(21,044)	(1,514)	(876)	(2,373)	(32,603)
Future development costs	(1,362)	(6,715)	(462)	(677)	(1,119)	(10,335)
Future income tax expenses	(923)	(60)	(935)	(12,419)	(1,768)	(16,105)
Future net cash flows	$ 3,013	$ 4,388	$ 1,709	$ 1,002	$ 1,641	$ 11,753
10 percent annual discount for estimated timing of cash flows	(1,041)	(3,658)	(625)	(571)	(167)	(6,062)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 1,972	$ 730	$ 1,084	$ 431	$ 1,474	$ 5,691
2008						
Future cash inflows	$ 11,295	$ -	$ 3,316	$ 8,952	$ 5,578	$ 29,141
Future production and administrative costs	(6,045)	-	(1,525)	(666)	(2,130)	(10,366)
Future development costs	(2,673)	-	(436)	(172)	(1,690)	(4,971)
Future income tax expenses	(443)	-	(429)	(7,422)	(64)	(8,358)
Future net cash flows	$ 2,134	$ -	$ 926	$ 692	$ 1,694	$ 5,446
10 percent annual discount for estimated timing of cash flows	(703)	-	(352)	(330)	(26)	(1,411)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 1,431	$ -	$ 574	$ 362	$ 1,668	$ 4,035
Standardized measure of discounted future net cash flows relating to discontinued operations	$ -	$ -	$ -	$ 20	$ 264	$ 284
2007						
Future cash inflows	$ 19,432	$ -	$ 9,787	$ 21,732	$ 13,449	$ 64,400
Future production and administrative costs	(5,769)	-	(1,314)	(671)	(2,982)	(10,736)
Future development costs	(1,299)	-	(552)	(124)	(2,002)	(3,977)
Future income tax expenses	(4,047)	-	(2,715)	(19,445)	(3,816)	(30,023)
Future net cash flows	$ 8,317	$ -	$ 5,206	$ 1,492	$ 4,649	$ 19,664
10 percent annual discount for estimated timing of cash flows	(3,297)	-	(2,094)	(713)	(593)	(6,697)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 5,020	$ -	$ 3,112	$ 779	$ 4,056	$ 12,967
Standardized measure of discounted future net cash flows relating to discontinued operations	$ -	$ -	$ -	$ 282	$ 246	$ 528

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Changes in the Standardized Measure of Discounted Future Net Cash Flows

(In millions)	2009	2008	2007
Sales and transfers of oil and gas produced, net of production and administrative costs	$ (4,876)	$ (6,863)	$ (4,613)
Net changes in prices and production and administrative costs related to future production	4,840	(18,683)	12,344
Extensions, discoveries and improved recovery, less related costs	1,399	663	1,816
Development costs incurred during the period	2,786	1,774	1,569
Changes in estimated future development costs	(3,641)	(1,436)	(1,706)
Revisions of previous quantity estimates	5,110	85	166
Net changes in purchases and sales of minerals in place	(159)	(13)	23
Accretion of discount	787	2,724	1,696
Net change in income taxes	(4,441)	12,633	(6,647)
Timing and other	(149)	184	(31)
Net change for the year	1,656	(8,932)	4,617
Beginning of the year	4,035	12,967	8,350
End of year	$ 5,691	$ 4,035	$ 12,967
Net change for the year from discontinued operations	$ -	$ 284	$ 528

MARATHON OIL CORPORATION
Supplementary Statistics (Unaudited)

(In millions)	December 31, 2009	2008	2007
Segment Income (Loss)			
Exploration and Production			
United States	$ 55	$ 869	$ 623
International	1,166	1,687	929
E&P segment	1,221	2,556	1,552
Oil Sands Mining	44	258	(63)
Integrated Gas	90	302	132
Refining, Marketing and Transportation	464	1,179	2,077
Segment income	1,819	4,295	3,698
Items not allocated to segments, net of income taxes	(356)	(767)	258
Net income	$ 1,463	$ 3,528	$ 3,956
Capital Expenditures[a]			
Exploration and Production			
United States	$ 1,420	$ 2,036	$ 1,353
International	742	935	1,073
E&P segment	2,162	2,971	2,426
Oil Sands Mining	1,115	1,038	165
Integrated Gas[b]	2	4	93
Refining, Marketing and Transportation	2,570	2,954	1,640
Discontinued Operations[c]	81	142	85
Corporate	42	37	57
Total	$ 5,972	$ 7,146	$ 4,466
Exploration Expenses			
United States	$ 153	$ 238	$ 274
International	154	251	180
Total	$ 307	$ 489	$ 454

(a) Capital expenditures include changes in accruals.

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

(c) Our businesses in Ireland and Gabon were sold in 2009. All periods have been recast to reflect these businesses in discontinued operations.

MARATHON OIL CORPORATION

Supplemental Statistics (Unaudited)

	2009	2008	2007
E&P Operating Statistics			
Net Liquid Hydrocarbon Sales (mbpd)			
United States	64	63	64
Europe	92	55	33
Africa	87	87	90
Total International	179	142	123
Worldwide Continuing Operations	243	205	187
Discontinued Operations	5	6	10
Worldwide	248	211	197
Natural gas liquids included in above	19	20	22
Natural Gas Sales (mmcfd)[c]			
United States	373	448	477
Europe	138	161	177
Africa	430	370	232
Total International	568	531	409
Worldwide Continuing Operations	941	979	886
Discontinued Operations	17	37	39
Worldwide	958	1,016	925
Total Worldwide Sales (mboepd)			
Continuing Operations	400	369	334
Discontinued Operations	7	12	17
Worldwide	407	381	351
Average Realizations[d]			
Liquid Hydrocarbons (per bbl)			
United States	$ 54.67	$ 86.68	$ 60.15
Europe	64.46	90.60	70.31
Africa	53.91	89.85	65.41
Total International	59.31	90.14	66.74
Worldwide Continuing Operations	58.09	89.07	64.47
Discontinued Operations	56.47	96.41	72.19
Worldwide	$ 58.06	$ 89.29	$ 64.86
Natural Gas (per mcf)			
United States	$ 4.14	$ 7.01	$ 5.73
Europe	4.90	7.67	6.49
Africa[e]	0.25	0.25	0.25
Total International	1.38	2.50	2.96
Worldwide Continuing Operations	2.47	4.56	4.45
Discontinued Operations	8.54	9.62	6.71
Worldwide	$ 2.58	$ 4.75	$ 4.54
OSM Operating Statistics[f]			
Net Synthetic Crude Sales (mbpd) [g]	32	32	4
Synthetic Crude Average Realization (per bbl)[d]	$ 56.44	$ 91.90	$ 71.07
Net Proved Bitumen Reserves at year-end (mmbbl)[h]	N/A	388	421

(c) Includes natural gas acquired for injection and subsequent resale of 22 mmcfd, 32 mmcfd and 47 mmcfd for the years 2009, 2008 and 2007.

(d) Excludes gains and losses on derivative instruments.

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

(f) The oil sands mining operations were acquired October 18, 2007. Daily volumes reported in 2007 represent activity after the acquisition date over total days in the period.

(g) Includes blendstocks.

(h) Prior to December 31, 2009, reserves related to oil sand mining were not included in the SEC's definition of oil and gas producing activities; therefore, bitumen reserves were reported separately for the OSM segment. See the Proved Reserves section of the supplemental statistics for 2009 information.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

(In millions, except as noted)	2009	2008	2007
Proved Reserves			
Net Proved Reserves at year-end (developed and undeveloped)			
Liquid Hydrocarbons (mmbbl)			
United States	170	178	166
International	452	454	475
Worldwide Continuing Operations	622	632	641
Discontinued Operations	-	4	9
Worldwide	622	636	650
Natural Gas (bcf)			
United States	820	1,085	1,007
International	1,904	2,134	2,299
Worldwide Continuing Operations	2,724	3,219	3,306
Discontinued Operations	-	132	144
Worldwide	2,724	3,351	3,450
Synthetic Crude Oil (mmbbls)[i]			
Canada	603	N/A	N/A
Total Proved Reserves (mmboe)	1,679	1,195	1,225
IG Operating Statistics			
Net Sales (mtpd) [j]			
LNG	6,642	6,285	3,310
Methanol	1,192	975	1,308
RM&T Operating Statistics			
Refinery Runs (mbpd)			
Crude oil refined	957	944	1,010
Other charge and blend stocks	196	207	214
Total	1,153	1,151	1,224
Refined Product Yields (mbpd)			
Gasoline	669	609	646
Distillates	326	342	349
Propane	23	22	23
Feedstocks and special products	62	96	108
Heavy fuel oil	24	24	27
Asphalt	66	75	86
Total	1,170	1,168	1,239
Refined Products Sales Volumes (mbpd) [k]	1,378	1,352	1,410
Refining and Wholesale Marketing Gross Margin (per gallon) [l]	$ 0.0610	$ 0.1166	$ 0.1848
Speedway SuperAmerica			
Retail outlets	1,603	1,617	1,636
Gasoline and distillate sales (millions of gallons)	3,232	3,215	3,356
Gasoline and distillate gross margin (per gallon)	$ 0.1141	$ 0.1387	$ 0.1119
Merchandise sales	$ 3,109	$ 2,838	$ 2,796
Merchandise gross margin	$ 775	$ 716	$ 705

(i) Beginning December 31, 2009, under revised SEC regulations, reserves related to oil sands mining are reported as synthetic crude oil (bitumen after upgrading), in combination with oil and gas producing activities.

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

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

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

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

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

Internal Control Over Financial Reporting

See Financial Statements and Supplementary Data – Management's Report on Internal Control over Financial Reporting and – Report of Independent Registered Public Accounting Firm. During the fourth quarter of 2009, there were no changes in our internal control over financial reporting that have materially affected, or were reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information concerning our directors required by this item is incorporated by reference to the material appearing under the heading "Election of Directors" in our Proxy Statement for the 2010 Annual Meeting of stockholders.

Our Board of Directors has established the Audit and Finance Committee and determined our "Audit Committee Financial Expert." The related information required by this item is incorporated by reference to the material appearing under the sub-heading "Audit and Finance Committee" located under the heading "The Board of Directors and Governance Matters" in our Proxy Statement for the 2010 Annual Meeting of Stockholders.

We have adopted a Code of Ethics for Senior Financial Officers. It is available on our website at http://www.marathon.com/Investor_Center/Corporate_Governance/Code_of_Ethics_for_Senior_Financial_Officers/.

Executive Officers of the Registrant

See Item 1. Business – Executive Officers of the Registrant for the names, ages and titles of our executive officers.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934, as amended, requires that our directors and executive officers, and persons who own more than ten percent of a registered class of our equity securities, file reports of beneficial ownership on Form 3 and changes in beneficial ownership on Form 4 or Form 5 with the SEC. Based solely on our review of the reporting forms and written representations provided to us by the individuals required to file reports, we believe that each of our executive officers and directors has complied with the applicable reporting requirements for transactions in our securities during the fiscal year ended December 31, 2009.

Item 11. Executive Compensation

Information required by this item is incorporated by reference to the material appearing under the heading "Executive Compensation Tables and Other Information;" under the sub-headings "Compensation Committee" and "Compensation Committee Interlocks and Insider Participation" under the heading "The Board of Directors and Governance Matters;" and under the heading "Compensation Committee Report" in our Proxy Statement for the 2010 Annual Meeting of stockholders.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information concerning security ownership of certain beneficial owners and management required by this item is incorporated by reference to the material appearing under the headings "Security Ownership of Certain Beneficial Owners" and "Security Ownership of Directors and Executive Officers" in our Proxy Statement for the 2010 Annual Meeting of stockholders.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table provides information as of December 31, 2009 with respect to shares of Marathon common stock that may be issued under our existing equity compensation plans:

- 2007 Incentive Compensation Plan (the "2007 Plan")
- 2003 Incentive Compensation Plan (the "2003 Plan") – No additional awards will be granted under this plan.
- 1990 Stock Plan – No additional awards will be granted under this plan.
- Deferred Compensation Plan for Non-Employee Directors – No additional awards will be granted under this plan.

	Column (a)	Column (b)	Column (c)
Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights[c]	Number of securities remaining available for future issuance under equity compensation plans[a]
Equity compensation plans approved by stockholders	17,537,150 [a]	$35.01	21,726,933 [d]
Equity compensation plans not approved by stockholders	91,457 [b]	N/A	-
Total	17,628,607	N/A	21,726,933

(a) Includes the following:

- 10,178,384 stock options outstanding under the 2007 Plan;
- 6,584,742 stock options outstanding under the 2003 Plan and the net number of stock-settled SARs that could be issued from this Plan. The number of stock-settled SARs is based on the closing price of Marathon common stock on December 31, 2009 of $31.22 per share;
- 403,100 stock options and SARs outstanding under the 1990 Stock Plan;
- 211,479 common stock units that have been credited to non-employee directors pursuant to the non-employee director deferred compensation program and the annual director stock award program established under the 2007 Plan and the 2003 Plan; common stock units credited under the 2007 Plan and the 2003 Plan were 80,054 and 131,425;
- 152,765 restricted stock units granted to non-officers under the 2007 Plan and outstanding as of December 31, 2009; and
- 6,680 restricted stock units granted to non-officers under the 2003 Plan and outstanding as of December 31, 2009.

In addition to the awards reported above 1,239,720 shares and 42,334 shares of restricted stock were issued and outstanding as of December 31, 2009, but subject to forfeiture restrictions under the 2007 Plan and the 2003 Plan.

(b) Reflects awards of common stock units made to non-employee directors under the Deferred Compensation Plan for Non-Employee Directors prior to April 30, 2003. When a non-employee director leaves the Board, he or she will be issued actual shares of Marathon common stock in place of the common stock units.

(c) Weighted-average exercise prices do not take the restricted stock units or common stock units into account as these awards have no exercise price.

(d) Reflects the shares available for issuance under the 2007 Plan. No more than 9,905,317 of these shares may be issued for awards other than stock options or stock appreciation rights. In addition, shares related to grants that are forfeited, terminated, cancelled or expire unexercised shall again immediately become available for issuance.

The Deferred Compensation Plan for Non-Employee Directors is our only equity compensation plan that has not been approved by our stockholders. Our authority to make equity grants under this plan was terminated effective April 30, 2003. Under the Deferred Compensation Plan for Non-Employee Directors, all non-employee directors were required to defer half of their annual retainers in the form of common stock units. On the date the retainer would have otherwise been payable to the non-employee director, we credited an unfunded bookkeeping account for each non-employee director with a number of common stock units equal to half of his or her annual retainer divided by the fair market value of our

common stock on that date. The ongoing value of each common stock unit equals the market price of a share of our common stock. When the non-employee director leaves the Board, he or she is issued actual shares of our common stock equal to the number of common stock units in his or her account at that time.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information required by this item is incorporated by reference to the material appearing under the heading "Certain Relationships and Related Person Transactions," and under the sub-heading "Board and Committee Independence" under the heading "The Board of Directors and Governance Matters" in our Proxy Statement for the 2010 Annual Meeting of stockholders.

Item 14. Principal Accounting Fees and Services

Information required by this item is incorporated by reference to the material appearing under the heading "Information Regarding the Independent Registered Public Accounting Firm's Fees, Services and Independence" in our Proxy Statement for the 2010 Annual Meeting of stockholders.

PART IV

Item 15. Exhibits, Financial Statement Schedules

A. Documents Filed as Part of the Report

1. Financial Statements (see Part II, Item 8. of this report regarding financial statements)

2. Financial Statement Schedules

   Financial statement schedules required under SEC rules but not included in this report are omitted because they are not applicable or the required information is contained in the consolidated financial statements or notes thereto.

3. Exhibits:

Any reference made to USX Corporation in the exhibit listing that follows is a reference to the former name of Marathon Oil Corporation, a Delaware corporation and the registrant, and is made because the exhibit being listed and incorporated by reference was originally filed before July 2001, the date of the change in the registrant's name. References to Marathon Ashland Petroleum LLC or MAP are references to the entity now known as Marathon Petroleum Company LLC.

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
2	**Plan of Acquisition, Reorganization, Arrangement, Liquidation or Succession**						
2.1	Holding Company Reorganization Agreement, dated as of July 1, 2001, by and among USX Corporation, USX Holdco, Inc. and United States Steel LLC	10-K	2.1	3/1/2007			
2.2	Agreement and Plan of Reorganization, dated as of July 31, 2001, by and between USX Corporation and United States Steel LLC	10-K	2.2	3/1/2007			
2.3++	Master Agreement, among Ashland Inc., ATB Holdings Inc., EXM LLC, New EXM Inc., Marathon Oil Corporation, Marathon Oil Company, Marathon Domestic LLC and Marathon Ashland Petroleum LLC, dated as of March 18, 2004 and Amendment No. 1 dated as of April 27, 2005	S-4/A	2.1	5/19/2005	333-119694		
2.4++	Amended and Restated Arrangement Agreement among Marathon Oil Corporation, 1339971 Alberta Ltd., Western Oil Sands Inc. and WesternZagros Resources Inc., dated as of September 14, 2007	S-3ASR	2.7	10/17/2007	333-146772		
2.5++	Amending Agreement among Marathon Oil Corporation, 1339971 Alberta Ltd, Western Oil Sands Inc. and WesternZagros Resources Inc., dated as of October 15, 2007	S-3ASR	2.8	10/17/2007	333-146772		

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
2.6++	Plan of Arrangement under Section 193 of the Business Corporations Act (Alberta)	S-3ASR	2.9	10/17/2007	333-146772		
3	**Articles of Incorporation and Bylaws**						
3.1	Restated Certificate of Incorporation of Marathon Oil Corporation	8-K	3.1	4/25/2007			
3.2	By-Laws of Marathon Oil Corporation	8-K	3.1	11/4/2008			
3.3	Specimen of Common Stock Certificate	8-K	3.3	5/14/2007			
3.4	Certificate of Designations of Special Voting Stock of Marathon Oil Corporation	10-Q	3.3	9/30/2007			
4	**Instruments Defining the Rights of Security Holders, Including Indentures**						
4.1	Five Year Credit Agreement dated as of May 20, 2004 among Marathon Oil Corporation, the Co-Agents and other Lenders party thereto, Bank of America, N.A., as Syndication Agent, ABN Ambro Bank N.V., Citibank, N.A. and Morgan Stanley Bank, as Documentation Agents and JPMorgan Chase Bank, as Administrative Agent					X	
4.2	Amendment No. 1 dated as of May 4, 2006 to Five-Year Credit Agreement dated as of May 20, 2004 among Marathon Oil Corporation, the Co-Agents and other Lenders party thereto, Bank of America, N.A., as Syndication Agent, Citibank, N.A. and Morgan Stanley Bank, as Documentation Agents and JPMorgan Chase Bank, as Administrative Agent	10-Q	4.1	3/31/2006			
4.3	Amendment No. 2 dated as of May 7, 2007 to Five-Year Credit Agreement dated as of May 20, 2004 among Marathon Oil Corporation, the Co-Agents and other Lenders party thereto, Bank of America, N.A., as Syndication Agent, Citibank, N.A. and Morgan Stanley Bank, as Documentation Agents and JPMorgan Chase Bank, as Administrative Agent	10-Q	4.1	6/30/2007			

Exhibit Number	Exhibit Description	Incorporated by Reference Form	Exhibit	Filing Date	SEC File No.	Filed Herewith	Furnished Herewith
4.4	Amendment No. 3 dated as of October 4, 2007 to Five-Year Credit Agreement dated as of May 20, 2004 among Marathon Oil Corporation, the Co-Agents and other Lenders party thereto, Bank of America, N.A., as Syndication Agent, Citibank, N.A. and Morgan Stanley Bank, as Documentation Agents and JPMorgan Chase Bank, as Administrative Agent	10-Q	4.1	9/30/2007			
4.5	Amendment No. 4 dated as of April 3, 2008 to Five-Year Credit Agreement dated as of May 20, 2004 among Marathon Oil Corporation, the Co-Agents and other Lenders party thereto, Bank of America, N.A., as Syndication Agent, Citibank, N.A. and Morgan Stanley Bank, as Documentation Agents and JPMorgan Chase Bank, as Administrative Agent	10-Q	4.2	3/31/2008			
4.6	Indenture dated February 26, 2002 between Marathon and The Bank of New York Trust Company, N.A., successor in interest to JPMorgan Chase Bank as Trustee, relating to senior debt securities of Marathon	S-3	4.4	7/26/2007	333-144874		
	Pursuant to CFR 229.601(b)(4)(iii), instruments with respect to long-term debt issues have been omitted where the amount of securities authorized under such instruments does not exceed 10% of the total consolidated assets of Marathon. Marathon hereby agrees to furnish a copy of any such instrument to the Commission upon its request.						
10	**Material Contracts**						
10.1	Financial Matters Agreement between USX Corporation and United States Steel LLC (converted into United States Steel Corporation) dated as of December 31, 2001	10-K	10.2	12/31/2007			
10.2	Exchangeable Share Provisions of 1339971 Alberta Ltd	S-3ASR	10.1	10/17/2007	333-146772		
10.3	Form of Support Agreement among Marathon Oil Corporation, 1339971 Alberta Ltd. and Marathon Canadian Oil Sands Holding Limited, dated as of October 18, 2007	S-3ASR	10.2	10/17/2007	333-146772		

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
10.4	Form of Voting and Exchange Trust Agreement among Marathon Oil Corporation, 1339971 Alberta Ltd., Marathon Canadian Oil Sands Holding Limited and Valiant Trust Company, dated as of October 18, 2007	S-3ASR	10.3	10/17/2007	333-146772		
10.5	Marathon Oil Corporation 2007 Incentive Compensation Plan (incorporated by reference to Appendix I to Marathon Oil Corporation's Definitive Proxy Statement on Schedule 14A filed on March 14, 2007).	14A	App. I	3/14/2007			
10.6	Form of Non-Qualified Stock Option Award Agreement for Officers granted under Marathon Oil Corporation's 2007 Incentive Compensation Plan, effective May 30, 2007	10-Q	10.2	6/30/2007			
10.7	Form of Restricted Stock Award Agreement granted under Marathon Oil Corporation's 2007 Incentive Compensation Plan, effective May 30, 2007 (incorporated by reference to Exhibit 10.3 to Marathon Oil Corporation's Form 10-Q for the quarter ended June 30, 2007).	10-Q	10.3	6/30/2007			
10.8	Form of Performance Unit Award Agreement (2007-2009 Performance Cycle) for Officers granted under Marathon Oil Corporation's 2007 Incentive Compensation Plan, effective May 30, 2007	10-Q	10.4	6/30/2007			
10.9	Marathon Oil Corporation 2003 Incentive Compensation Plan, Effective January 1, 2003					X	
10.10	Marathon Oil Corporation 1990 Stock Plan, as Amended and Restated, Effective January 1, 2002	10-Q	10.1	9/30/2008			
10.11	First Amendment to Marathon Oil Corporation 1990 Stock Plan (as Amended and Restated) Effective January 1, 2002	10-Q	10.2	9/30/2008			
10.12	Marathon Oil Corporation Deferred Compensation Plan for Non-Employee Directors (Amended and Restated as of January 1, 2009).	10-K	10.14	2/27/2009			
10.13	Form of Non-Qualified Stock Option Grant for Executive Officers granted under Marathon Oil Corporation's 1990 Stock Plan, as amended and restated effective January 1, 2002	10-Q	10.3	9/30/2004			

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
10.14	Form of Non-Qualified Stock Option Grant for MAP officers granted under Marathon Oil Corporation's 1990 Stock Plan, as amended and restated effective January 1, 2002	10-K	10.14	12/31/2005			
10.15	Form of Non-Qualified Stock Option with Tandem Stock Appreciation Right Award Agreement for Chief Executive Officer granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan, effective January 1, 2003					X	
10.16	Form of Non-Qualified Stock Option with Tandem Stock Appreciation Right Award Agreement for Executive Committee members granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan, effective January 1, 2003					X	
10.17	Form of Non-Qualified Stock Option with Tandem Stock Appreciation Right Award Agreement for Officers granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan, effective January 1, 2003					X	
10.18	Form of Non-Qualified Stock Option Award Agreement for MAP officers granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan, effective January 1, 2003					X	
10.19	Form of Stock Appreciation Right Award Agreement for Chief Executive Officer granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan, effective January 1, 2003					X	
10.20	Form of Stock Appreciation Right Award Agreement for Executive Committee members granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan, effective January 1, 2003					X	
10.21	Form of Stock Appreciation Right Award Agreement for Officers granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan, effective January 1, 2003					X	

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
10.22	Form of Non-Qualified Stock Option Award Agreement granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan					X	
10.23	Form of Officer Restricted Stock Award Agreement granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan					X	
10.24	Form of Performance Unit Award Agreement (2005-2007 Performance Cycle) granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan					X	
10.25	Form of Performance Unit Award Agreement (2010-2012 Performance Cycle) granted under Marathon Oil Corporation's 2007 Incentive Compensation Plan					X	
10.26	Form of Non-Qualified Stock Option Award Agreement granted under Marathon Oil Corporation's 2007 Incentive Compensation Plan					X	
10.27	Form of Officer Restricted Stock Award Agreement granted under Marathon Oil Corporation's 2007 Incentive Compensation Plan					X	
10.28	Marathon Oil Company Excess Benefit Plan (Amended and Restated as of January 1, 2009).	10-K	10.27	2/27/2009			
10.29	Marathon Oil Company Deferred Compensation Plan.	10-K	10.28	2/27/2009			
10.30	Marathon Petroleum Company LLC Excess Benefit Plan	10-K	10.29	2/27/2009			
10.31	Marathon Petroleum Company LLC Deferred Compensation Plan.	10-K	10.30	2/27/2009			
10.32	Speedway SuperAmerica LLC Excess Benefit Plan	10-K	10.31	2/27/2009			
10.33	Executive Tax, Estate, and Financial Planning Program	10-K	10.32	2/27/2009			
10.34	EMRO Marketing Company Deferred Compensation Plan	10-K	10.33	2/27/2009			
10.35	Speedway SuperAmerica LLC Deferred Compensation Plan.	10-K	10.34	2/27/2009			
10.36	Executive Change in Control Severance Benefits Plan.	10-K	10.35	2/27/2009			
12.1	Computation of Ratio of Earnings to Fixed Charges.					X	
14.1	Code of Ethics for Senior Financial Officers					X	

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
21.1	List of Significant Subsidiaries.					X	
23.1	Consent of Independent Registered Public Accounting Firm.					X	
23.2	Consent of GLJ Petroleum Consultants, independent petroleum engineers and geologists					X	
23.3	Consent of Ryder Scott, independent petroleum engineers and geologists					X	
23.4	Consent of Netherland, Sewell & Associates, independent petroleum engineers and geologists					X	
31.1	Certification of President and Chief Executive Officer pursuant to Rule 13(a)-14 and 15(d)-14 under the Securities Exchange Act of 1934.					X	
31.2	Certification of Executive Vice President and Chief Financial Officer pursuant to Rule 13(a)-14 and 15(d)-14 under the Securities Exchange Act of 1934.					X	
32.1	Certification of President and Chief Executive Officer pursuant to 18 U.S.C. Section 1350.					X	
32.2	Certification of Executive Vice President and Chief Financial Officer pursuant to 18 U.S.C. Section 1350.					X	
99.1	Report of GLJ Petroleum Consultants, independent petroleum engineers and geologists					X	
99.2	Summary report of audits performed by Netherland, Sewell & Associates, independent petroleum engineers and geologists					X	
99.3	Summary report of audits performed by Ryder Scott, independent petroleum engineers and geologists					X	
101.INS	XBRL Instance Document.						X
101.SCH	XBRL Taxonomy Extension Schema.						X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.						X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.						X
101.LAB	XBRL Taxonomy Extension Label Linkbase.						X
101.DEF	XBRL Taxonomy Extension Definition Linkbase.						X

++ **Marathon agrees to furnish supplementally a copy of any omitted schedule to the United States Securities and Exchange Commission upon request**

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

February 26, 2010

MARATHON OIL CORPORATION

By: /s/ MICHAEL K. STEWART

Michael K. Stewart
Vice President, Accounting and Controller

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on February 26, 2010 on behalf of the registrant and in the capacities indicated.

Signature	Title
/s/ THOMAS J. USHER Thomas J. Usher	Chairman of the Board and Director
/s/ CLARENCE P. CAZALOT, JR. Clarence P. Cazalot, Jr.	President and Chief Executive Officer and Director
/s/ JANET F. CLARK Janet F. Clark	Executive Vice President and Chief Financial Officer
/s/ MICHAEL K. STEWART Michael K. Stewart	Vice President, Accounting and Controller
/s/ GREGORY H. BOYCE Gregory H. Boyce	Director
/s/ DAVID A. DABERKO David A. Daberko	Director
/s/ WILLIAM L. DAVIS William L. Davis	Director
/s/ SHIRLEY ANN JACKSON Shirley Ann Jackson	Director
/s/ PHILIP LADER Philip Lader	Director
/s/ CHARLES R. LEE Charles R. Lee	Director
/s/ MICHAEL E. J. PHELPS Michael E. J. Phelps	Director
/s/ DENNIS H. REILLEY Dennis H. Reilley	Director
/s/ SETH E. SCHOFIELD Seth E. Schofield	Director
/s/ JOHN W. SNOW John W. Snow	Director

Corporate Information

Corporate Headquarters
5555 San Felipe Road
Houston, TX 77056-2723

Marathon Oil Corporation Web Site
www.marathon.com

Investor Relations Office
5555 San Felipe Road (77056-2723)
P.O. Box 3128 (77253-3128)
Houston, TX

Howard J. Thill, Vice President,
Investor Relations and Public Affairs
+1 713-296-4140

Chris C. Phillips, Manager, Investor Relations
+1 713-296-3213

Notice of Annual Meeting
The 2010 Annual Meeting of Stockholders will be held in Houston, Texas, on April 28, 2010.

Independent Accountants
PricewaterhouseCoopers LLP
1201 Louisiana, Suite 2900
Houston, TX 77002-5678

Stock Exchange Listings
New York Stock Exchange (Principal Exchange)
Chicago Stock Exchange

Common Stock Symbol
MRO

Principal Stock Transfer Agent
Computershare
250 Royall Street
Canton, MA 02021
888-843-5542 (Toll free - U.S., Canada, Puerto Rico)
+1 781-575-4735 (non-U.S.)
web.queries@computershare.com

Annual Report on Form 10-K
Additional copies of the Marathon 2009 Annual Report may be obtained by contacting:
Public Affairs
5555 San Felipe Road
Room 4150
Houston, TX 77056-2723
+1 713-296-3911

Dividends
Dividends on Common Stock, as declared by the Board of Directors, are normally paid on the 10th day of March, June, September and December.

Dividend Checks Not Received / Electronic Deposit
If you do not receive your dividend check on the appropriate payment date, we suggest that you wait at least 10 days after the payment date to allow for any delay in mail delivery. After that time, advise Computershare by phone or in writing to issue a replacement check. You may contact Computershare to authorize electronic deposit of your dividends or interest into your bank account.

Dividend Reinvestment and Direct Stock Purchase Plan
The Dividend Reinvestment and Direct Stock Purchase Plan provides stockholders with a convenient way to purchase additional shares of Marathon Oil Corporation Common Stock without payment of any brokerage fees or service charges through investment of cash dividends or through optional cash payments. Stockholders of record can request a copy of the Plan Prospectus and an authorization form from Computershare. Beneficial holders should contact their brokers.

Lost Stock Certificate
If a stock certificate is lost, stolen or destroyed, notify Computershare in writing so that a stop transfer can be placed on the missing certificate. Computershare will send you the necessary forms and instructions for obtaining a replacement certificate. You may be required to obtain and pay for the cost of an indemnity bond. If you find the missing certificate, notify Computershare in writing immediately so that the stop transfer can be removed. To avoid loss, theft or destruction, we recommend that you keep your certificates in a safe place, such as a safe deposit box at your bank.

Taxpayer Identification Number
Federal law requires that each stockholder provide a certified Taxpayer Identification Number (TIN) for his/her stockholder account. For individual stockholders, your TIN is your Social Security Number. If you do not provide a certified TIN, Computershare may be required to withhold 28 percent for federal income taxes from your dividends.

Address Change
It is important that you notify Computershare immediately, by phone, in writing or by fax, when you change your address. Seasonal addresses can be entered for your account.

Range of Marathon Stock Sale Prices and Dividends Paid

	2009		
Quarter	High	Low	Dividend
First	$29.87	$20.92	$0.24
Second	33.41	27.08	0.24
Third	33.88	28.03	0.24
Fourth	35.27	30.48	0.24
Year	$35.27	$20.92	$0.96

MARATHON
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