MARATHON OIL CORP
Form 10-K
February 27, 2009

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, 2008

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 þ 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 þ

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 þ 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. þ

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 þ 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 þ

The aggregate market value of Common Stock held by non-affiliates as of June 30, 2008: $36,559 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 707,524,845 shares of Marathon Oil Corporation Common Stock outstanding as of January 31, 2009.

Documents Incorporated By Reference:

Portions of the registrant s proxy statement relating to its 2009 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.

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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, project, could, may, should, would or similar words, indicating that future outcomes are uncertain. In accordance with safe harbor provisi 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, bitumen and refined products; levels of worldwide prices of liquid hydrocarbons, natural gas and refined products; levels of reserves of liquid hydrocarbons, natural gas and bitumen; 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 outside-operated interest in the 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.

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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 by-products; 3) Refining, Marketing and Transportation (RM&T) refines, markets and transports crude oil and petroleum products, primarily in the Midwest, upper Great Plains, Gulf Coast and southeastern regions of the United States; and 4) Integrated Gas (IG) markets and transports products manufactured from natural gas, such as liquefied natural gas (LNG) and methanol, on a worldwide basis, and is developing other projects to link stranded natural gas resources with key demand areas. For operating segment and geographic financial information, see Note 10 to the consolidated financial statements.

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.

We conduct exploration, development and production activities in ten countries: the United States, Angola, Canada, Equatorial Guinea, Gabon, Indonesia, Ireland, Libya, Norway and the United Kingdom.

Our 2008 worldwide net liquid hydrocarbon sales averaged 211 thousand barrels per day (mbpd). Our 2008 worldwide net natural gas sales, including natural gas acquired for injection and subsequent resale, averaged 1,016 million cubic feet per day (mmcfd). In total, our 2008 worldwide net sales averaged 381 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.

Exploration

In the United States during 2008, we drilled 71 gross (48 net) exploratory wells of which 60 gross (42 net) wells encountered commercial quantities of hydrocarbons. Of these 60 wells, 3 were temporarily suspended or in the process of being completed at year end. Internationally, we drilled 12 gross (3 net) exploratory wells of which 11 gross (3 net) wells encountered commercial quantities of hydrocarbons. Of these 11 wells, 5 gross (1 net) wells were temporarily suspended or were in the process of being completed at December 31, 2008.

United States The Gulf of Mexico continues to be a core area. At the end of 2008, we had interests in 103 blocks in the Gulf of Mexico, including 97 in the deepwater area. We have been awarded 42 blocks on which we were the high bidder in the federal Outer Continental Shelf Lease Sales No. 205 and 206 conducted by the U.S. Minerals Management Service (MMS) in late 2007 and early 2008. Our initial net investment in these blocks was $343 million. We own 100 percent of fifteen of the blocks. We acquired the remaining blocks in conjunction with partners. Our plans call for initial drilling on some of these leases in 2009 and 2010.

In 2008, a successful appraisal well was drilled on the Stones prospect located on Walker Ridge Block 508 after a 2005 discovery. We hold a 25 percent outside-operated interest in the Stones prospect. In the third quarter of 2008, we announced a Gulf of Mexico deepwater discovery on the Gunflint prospect located on Mississippi Canyon Block 948. We own a 13 percent outside-operated interest in the prospect. In the first quarter of 2009, we participated in a deepwater discovery on the Shenandoah prospect located on Walker Ridge Block 52. We own a 20 percent outside-operated interest in the prospect.

In 2008, we successfully completed our first horizontal well in the Woodford Shale resource play in the Anadarko Basin of Oklahoma. We are currently participating in additional horizontal wells in the area where we hold 30,000 net acres.

We hold acreage in two additional emerging shale resource plays in the U.S. In the Appalachian Basin we hold 65,000 net acres in the Marcellus Shale resource play in Pennsylvania and West Virginia. We hold 25,000 net acres, primarily in Texas, in the Haynesville Shale resource play located in north Louisiana and east Texas. Initial drilling on some of these leases is planned for 2009.

Angola Offshore Angola, we hold a 10 percent outside-operated interest in Block 31 and a 30 percent outside-operated interest in Block 32. Through December 2008, 28 discoveries on these blocks have been announced, including the Portia and Dione discoveries on Angola Block 31 in 2008.

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Norway We hold interests in over 510,000 gross acres offshore Norway, including production license 505 (PL 505) that was awarded in January 2009. In 2009, exploration drilling is expected to commence on additional prospects with the potential to be tied back to the Alvheim complex.

Indonesia We are the operator and hold a 70 percent interest in the Pasangkayu Block offshore Indonesia. The 1.2 million acre 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. We expect to begin exploratory drilling in early 2010. Additionally, in October 2008, we were granted a 49 percent interest and operatorship in the Bone Bay Block offshore Indonesia. The Bone Bay Block is 200 miles southeast of our Pasangkayu Block. Current exploration plans for Bone Bay call for the acquisition of seismic data starting in 2010, followed by drilling in 2011.

We are the operator of a drilling rig consortium that has secured a two-year contract for a deepwater exploration drilling rig. The rig will be used for deepwater exploration activities by us and by five other companies in Indonesia. The participants have the right to extend this rig commitment.

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.

Equatorial Guinea During 2004, we announced the Deep Luba and Gardenia discoveries on the Alba Block, in which we hold a 63 percent operated interest, and the Corona well on Block D, where we are the operator with a 90 percent interest. 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.

Libya We hold a 16 percent outside-operated interest in the Waha concessions, which encompass almost 13 million acres located in the Sirte Basin. Our exploration program in 2008 included the drilling of three wells, all of which were successful. Most of these discoveries extended previously defined hydrocarbon accumulations.

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. Initial test drilling on the 100 percent interest Birchwood prospect positively confirmed bitumen presence with additional test drilling required to confirm reservoir quality.

United Kingdom We have a 45 percent interest in five exploratory U.K. onshore coal seam gas (CSG) licenses. Drilling has been completed in five exploration wells in three of the licenses. One test well was completed in 2007 and three lateral wells for production testing were drilled in 2008. We and our partners were awarded 11 new blocks for CSG exploration and potential future development during the 13th Onshore Licensing Round in 2008. After the 2008 licensing our interest covers 520,000 acres. We are the operator of these new licenses and have a 55 percent working interest.

Production (including development activities)

United States Our U.S. operations accounted for 30 percent of our 2008 worldwide net liquid hydrocarbon sales volumes and 44 percent of our worldwide net natural gas sales volumes.

During 2008, our net sales in the Gulf of Mexico averaged 23 mbpd of liquid hydrocarbons, representing 36 percent of our total U.S. net liquid hydrocarbon sales, and 20 mmcfd of natural gas, representing five percent of our total U.S. net natural gas sales. At year end 2008, we held interests in six producing fields and five platforms in the Gulf of Mexico, of which we operate one platform.

Hurricanes Gustav and Ike impacted Gulf of Mexico operations in the latter part of the third quarter of 2008, resulting in approximately 9.5 net mboepd being shut-in during the quarter. The Ewing Bank development resumed production in October 2008, but the outside-operated Ursa and Troika fields were shut-in for repairs until November 2008 and January 2009, respectively, impacting fourth quarter sales by approximately 7 mboepd. We have a 65 percent working interest in Ewing Bank, a four percent overriding royalty interest in Ursa and a 50 percent working interest in Troika.

We own a 50 percent outside-operated interest in the Petronius field on Viosca Knoll Blocks 786 and 830. The Petronius platform also provides processing and transportation services to adjacent third-party fields. For example, Petronius processes liquid hydrocarbons from our Perseus field which commenced production in April 2005 and is located five miles from the platform.

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The Neptune development in the Gulf of Mexico commenced production of liquid hydrocarbons and natural gas in July 2008. We hold a 30 percent outside-operated working interest in this development located on Atwater Valley area in the Gulf of Mexico, 120 miles off the coast of Louisiana. The development plan included seven subsea wells tied back to a stand-alone platform and six wells have been drilled and completed.

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

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

We produce natural gas in the Cook Inlet and adjacent Kenai Peninsula of Alaska. In 2008, our net natural gas sales from Alaska averaged 126 mmcfd, representing 28 percent of our total U.S. net natural gas sales volumes. 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.

Net liquid hydrocarbon and natural gas sales from our Wyoming fields averaged 19 mbpd and 123 mmcfd in 2008. Our Wyoming net natural gas sales decreased from the prior year primarily as a result of natural field declines, partially offset by new wells in the Wamsutter Field and Powder River Basin areas. Development of the Powder River Basin continued in 2008 with 100 operated wells drilled, which was down from the 170 wells drilled in 2007. Additional development of our southwest Wyoming interests continued in 2008 where we participated in the drilling of six wells.

We also have domestic natural gas operations in Oklahoma, east Texas and north Louisiana, with combined net sales of 137 mmcfd in 2008, and liquid hydrocarbon operations in the Permian Basin of southeast New Mexico and west Texas, with net sales of 11 mbpd in 2008.

We hold 320,000 acres in the Williston Basin (the Bakken Shale resource play). The majority of the acreage is located in North Dakota with the remainder in eastern Montana. This represents a substantial position in the Bakken Shale where approximately 225 locations will be drilled over the next four to five years. We currently have four operated drilling rigs running and ended 2008 with December average net sales of 8.2 mboepd.

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 150 wells over the next five years. Drilling and production commenced in late 2007. We currently have one operated drilling rig running and ended 2008 with December average net sales of 10 mmcfd.

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. 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 26 percent working interest. Net liquid hydrocarbon sales from the Brae area averaged 12 mbpd in 2008. Net Brae natural gas sales averaged 119 mmcfd, or 21 percent, of our international natural gas sales volumes in 2008.

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

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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 and has the capacity for almost 1 bcf per day of third-party natural gas from the Britannia, Atlantic and Cromarty fields.

In the U.K. Atlantic Margin, we own a 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 12 mbpd of liquid hydrocarbons and 6 mmcfd of natural gas in 2008.

Norway Norway is a strategic and growing core area, which complements our long-standing operations in the U.K. sector of the North Sea discussed above. We were approved for our first operatorship on the Norwegian continental shelf in 2002, where today we operate seven licenses, including the PL 505, which was awarded in January 2009.

The operated Alvheim complex located on the Norwegian continental shelf commenced production in June 2008. The complex consists of a floating production, storage and offloading vessel (FPSO) with subsea infrastructure. Produced oil is transported by shuttle tanker and produced natural gas transported to the SAGE system using a new 14-inch diameter, 24-mile cross border pipeline. First production to the complex was from the Alvheim development which is comprised of the Kameleon and Kneler discoveries, in which we have a 65 percent working interest, and the Boa discovery, in which we have a 58 percent working interest. At the end of 2008, the Alvheim development included ten producing wells and two water disposal wells. The nearby Vilje discovery, in which we own a 47 percent outside-operated working interest, began producing through the Alvheim complex in August 2008. The two Vilje development wells were drilled and completed in 2007. Additionally, in 2007, the Norwegian government approved a plan for development and operation to develop the Volund field as a subsea tie-back to the Alvheim complex. The Volund development will consist of three production wells and one water disposal well, all to be drilled in the 2009 and 2010. The Volund development, in which we own a 65 percent working interest and serve as operator, is expected to begin production in late 2009.

In addition, we hold a 28 percent outside-operated interest in the Gudrun field, located 120 miles off the coast of Norway, where a successful appraisal well was drilled in 2006. 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. A final investment decision is expected in 2009.

On October 31, 2008, we closed the sale of our non-core, 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.

Ireland In December 2008, we announced an agreement to sell our wholly-owned subsidiary which owns our producing properties in Ireland. Closing is subject to customary closing conditions. Properties included in the sale are our 100 percent working interest in the Kinsale Head, Ballycotton and Southwest Kinsale natural gas fields and our 87 percent operated working interest in the Seven Heads natural gas field in the Celtic Sea offshore Ireland. Also included is a 100 percent interest in our gas storage business which allows us to provide full third-party storage services from the Southwest Kinsale field.

We own a 19 percent working interest in the outside-operated Corrib natural gas development project, located 40 miles off Ireland s northwest coast, where six of the seven wells necessary to develop the field have been drilled. Four of these wells were completed and tested at the end of 2008. Terminal construction and offshore pipe installation are currently underway and onshore pipeline installation is planned to commence in 2009. The operator expects first production from the field in late 2010 or early 2011.

Equatorial Guinea We own a 63 percent operated working interest in the Alba field offshore Equatorial Guinea During 2008, net liquid hydrocarbon sales average 41 mbpd or 28 percent of our international liquid hydrocarbon sales volumes, and net natural gas sales averaged 366 mmcfd, or 64 percent of our international natural gas sales. Net liquid hydrocarbon sales volumes in 2008 included 26 mbpd of 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 supplied to the LPG plant under a long-term contract at a fixed price. During 2008, a gross 883 mmcfd of natural gas was supplied to the LPG production facility and our net liquid hydrocarbon sales volumes in 2008 included 11 mbpd of LPG and 4 mbpd of secondary condensate produced by Alba Plant LLC.

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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). AMPCO operates a methanol plant and EGHoldings operates an LNG production facility, both located on Bioko Island. Alba field dry natural gas, 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 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 2008, a gross 94 mmcfd of dry natural gas was supplied to the methanol plant and a gross 565 mmcfd of dry gas was supplied to the LNG production facility. Any remaining dry gas is returned offshore and reinjected into the Alba reservoir for later production.

Angola 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. Key contracts were awarded and construction work commenced in the second half of 2008. A total of 48 production and injection wells are planned for the PSVM development. Other discoveries on Block 31 comprise potential development areas in the southeast and middle portions of the block. Seven of the Block 32 discoveries form a potential development in the eastern area of that block.

Libya We resumed operations in Libya in 2006, holding a 16 percent outside-operated interest in the Waha concessions. Net liquid hydrocarbon sales in Libya averaged 46 mbpd in 2008 compared to 45 mbpd in 2007. The 2008 net liquid hydrocarbon sales in Libya represented 31 percent of our international liquid hydrocarbon sales volumes. Net natural gas sales in Libya averaged 4 mmcfd in 2008.

Gabon We are the operator of the Tchatamba South, Tchatamba West and Tchatamba Marin fields offshore Gabon with a 56 percent working interest. Net sales in Gabon averaged 6 mbpd of liquid hydrocarbons in 2008. Production from these three fields is processed on a single offshore facility at Tchatamba Marin, with the processed oil being transported through an offshore and onshore pipeline to an outside-operated storage facility.

Other Matters

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

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

The above discussion of the E&P segment includes forward-looking statements with respect to anticipated future exploratory and development drilling, Blocks 31 and 32 offshore Angola, the Equatorial Guinea discoveries, the timing of production from the Woodford Shale resource play, the Droshky and Ozona developments in the Gulf of Mexico, the Volund development, the sale of a subsidiary which owns producing properties in Ireland and the Corrib project. 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. Except for the Volund development, 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 possible developments on Blocks 31 and 32 offshore Angola, and the Equatorial Guinea discoveries could further be affected by presently known data concerning size and character of reservoirs, economic recoverability, future drilling success and production experience. Factors that could affect the sale of the subsidiary include customary closing conditions. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

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Reserves

At December 31, 2008, our net proved liquid hydrocarbon and natural gas reserves totaled 1,195 million boe, of which 43 percent were located in Organization for Economic Cooperation and Development (OECD) countries. The following table sets forth estimated quantities of net proved liquid hydrocarbon and natural gas reserves at the end of each of the last three years.

Estimated Quantities of Net Proved Liquid Hydrocarbon and Natural Gas Reserves at December 31

	Developed			Developed and Undeveloped		
	2008	2007	2006	2008	2007	2006
Liquid Hydrocarbons *(Millions of barrels)*						
United States	137	135	150	178	166	172
Europe	81	32	35	104	115	108
Africa	296	304	381	354	369	397
WORLDWIDE	514	471	566	636	650	677
Developed reserves as a percent of total net proved reserves	81%	72%	84%			
Natural Gas *(Billions of cubic feet)*						
United States	839	761	857	1,085	1,007	1,069
Europe	129	173	238	291	382	444
Africa	1,382	1,515	648	1,975	2,061	1,997
WORLDWIDE	2,350	2,449	1,743	3,351	3,450	3,510
Developed reserves as a percent of total net proved reserves	70%	71%	50%			
Total BOE *(Millions of barrels)*						
United States	277	262	293	359	334	350
Europe	103	61	75	153	179	182
Africa	526	556	489	683	712	730
WORLDWIDE	906	879	857	1,195	1,225	1,262
Developed reserves as a percent of total net proved reserves	76%	72%	68%			

The following table sets forth changes in estimated quantities of proved liquid hydrocarbon and natural gas reserves:

Changes in Estimated Quantities of Net Proved Liquid Hydrocarbon and Natural Gas Reserves

(Millions of barrels of oil equivalent)	2008
Beginning of year	1,225
Revisions of previous estimates	23
Extensions, discoveries, additions and improved recovery[a]	87
Production	(137)
Sales of reserves in place[b]	(3)
End of year	1,195

[a] Additions were principally in Norway, the Gulf of Mexico and Libya.

(b) The sale of outside-operated properties in Norway was the most significant disposition.

During 2008, we transferred 126 million boe from proved undeveloped to proved developed reserves. Costs incurred for the periods ended December 31, 2008, 2007 and 2006 relating to the development of proved undeveloped liquid hydrocarbon and natural gas reserves, were $1,189 million, $1,250 million and $1,010 million. Of the 289 million boe of proved undeveloped reserves at year-end 2008, 64 percent of the volume is associated with projects that have been included in proved reserves for more than three years while 19 percent of the proved undeveloped reserves were added during 2008. As of December 31, 2008, estimated future development costs relating to the development of proved undeveloped liquid hydrocarbon and natural gas reserves for the years 2009 through 2011 are projected to be $1,244 million, $508 million and $262 million.

The above estimated quantities of net proved liquid hydrocarbon and natural gas reserves and estimated future development costs relating to the development of proved undeveloped liquid hydrocarbon and natural gas

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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.

For a discussion of the proved liquid hydrocarbon and natural gas reserve estimation process, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Estimates Estimated Net Recoverable Reserve Quantities Proved Liquid Hydrocarbon and Natural Gas Reserves, and 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 Estimated Quantities of Proved Oil and Natural Gas Reserves. We filed reports with the U.S. Department of Energy (DOE) for 2007 disclosing our total year-end estimated liquid hydrocarbon and natural gas reserves. The year-end estimates reported to the DOE are the same estimates reported in the Supplementary Information on Oil and Gas Producing Activities.

Delivery Commitments

We sell liquid hydrocarbons and natural gas under a variety of contractual arrangements, some of which specify the delivery of a fixed and determinable quantity. Worldwide, we are contractually committed to deliver 126 bcf of natural gas in the future. These contracts have various expiration dates through the year 2018. Our proved reserves in Alaska, the United Kingdom and other locations, are sufficient to fulfill these delivery commitments.

Net Liquid Hydrocarbon and Natural Gas Sales

The following tables set forth the daily average net sales volumes of liquid hydrocarbons and natural gas for each of the last three years.

Net Liquid Hydrocarbon Sales[(a)]			
(Thousands of barrels per day)	2008	2007	2006
United States[(b)]	63	64	76
Europe[(c)]	55	33	35
Africa[(c)]	93	100	112
Worldwide Continuing Operations	211	197	223
Discontinued Operations[(d)]			12
WORLDWIDE	211	197	235
Net Natural Gas Sales[(e)]			
(Millions of cubic feet per day)	2008	2007	2006
United States[(b)]	448	477	532
Europe[(f)]	166	169	197
Africa	370	232	72
WORLDWIDE	984	878	801

(a) Includes crude oil, condensate and natural gas liquids.
(b) Represents net sales from leasehold ownership, after royalties and interests of others.
(c) Represents equity tanker liftings and direct deliveries of liquid hydrocarbons. The amounts correspond with the basis for fiscal settlements with governments. Crude oil purchases, if any, from host governments are excluded.
(d) Represents the Russian oil exploration and production businesses that were sold in June 2006.
(e) Represents net sales after royalties, except for Ireland where amounts are before royalties.
(f) Excludes volumes acquired from third parties for injection and subsequent resale of 32 mmcfd, 47 mmcfd and 46 mmcfd in 2008, 2007 and 2006.

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Productive and Drilling Wells

The following tables set forth productive wells and service wells as of December 31, 2008, 2007 and 2006 and drilling wells as of December 31, 2008.

Gross and Net Wells

		Productive Wells[a] Oil		Productive Wells[a] Natural Gas		Service Wells[b]		Drilling Wells[c]	
		Gross	Net	Gross	Net	Gross	Net	Gross	Net
2008	United States	5,856	2,140	5,411	3,846	2,703	822	77	50
	Europe	64	26	67	40	26	10	2	1
	Africa	968	162	13	9	97	18	7	1
	WORLDWIDE	6,888	2,328	5,491	3,895	2,826	850	86	52
2007	United States	5,864	2,111	5,184	3,734	2,737	838		
	Europe	54	20	76	41	29	11		
	Africa	964	161	13	9	99	18		
	WORLDWIDE	6,882	2,292	5,273	3,784	2,865	867		
2006	United States	5,661	2,068	5,554	4,063	2,729	834		
	Europe	51	19	75	41	31	12		
	Africa	925	155	13	9	100	19		
	WORLDWIDE	6,637	2,242	5,642	4,113	2,860	865		

(a) Includes active wells and wells temporarily shut-in. Of the gross productive wells, wells with multiple completions operated by Marathon totaled 276, 303 and 294 as of December 31, 2008, 2007 and 2006. Information on wells with multiple completions operated by others is unavailable to us.

(b) Consists of injection, water supply and disposal wells.

(c) Consists of exploratory and development wells.

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[a]

		Development[b] Oil	Development[b] Natural Gas	Development[b] Dry	Development[b] Total	Exploratory Oil	Exploratory Natural Gas	Exploratory Dry	Exploratory Total	Total
2008	United States	38	161		199	33	8	6	47	246
	International	8	1		9	1	2	1	4	13
	WORLDWIDE	46	162		208	34	10	7	51	259
2007	United States	9	172		181	9	13	12	34	215
	International	7			7	3	1	2	6	13
	WORLDWIDE	16	172		188	12	14	14	40	228

2006	United States	32	186	5	223	3	8	3	14	237
	International	51	1		52	19		6	25	77
	WORLDWIDE	83	187	5	275	22	8	9	39	314

(a) Includes the number of wells completed during the applicable year regardless of the year in which drilling was initiated. Excludes any wells where drilling operations were continuing or were temporarily suspended as of the end of the applicable year. A dry well is a well found to be incapable of producing hydrocarbons in sufficient quantities to justify completion. A productive well is an exploratory or development well that is not a dry well.

(b) Indicates wells drilled in the proved area of an oil or natural gas reservoir.

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Acreage

The following tables set forth, by geographic area, the developed and underdeveloped exploration and production acreage that we hold as of December 31, 2008.

Gross and Net Acreage

	Developed		Undeveloped		Developed and Undeveloped	
(Thousands of acres)	Gross	Net	Gross	Net	Gross	Net
United States	1,318	1,035	1,612	1,169	2,930	2,204
Europe	493	393	1,555	617	2,048	1,010
Africa	12,978	2,151	2,787	654	15,765	2,805
Other International			2,535	1,471	2,535	1,471
WORLDWIDE	14,789	3,579	8,489	3,911	23,278	7,490

Oil Sands Mining

Through our acquisition of Western, 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 and upgrades the bitumen to synthetic crude oil. The AOSP s asset is the mining and extraction operations of the Muskeg River mine located near Fort McMurray, Alberta, which began bitumen production in 2003, together with Scotford upgrading infrastructure located northeast of Edmonton, Alberta. The underlying developed leases are held for the duration of the project, with royalties paid to the province of Alberta. As of December 31, 2008, we have rights to participate in developed and undeveloped leases totaling approximately 215,000 gross (45,000 net) acres. Prior to December 6, 2009, we are entitled to participate in any new land acquisitions by either of the other AOSP owners within a defined area of mutual interest.

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. Bitumen production from the mine is taken by pipeline to the Scotford upgrader.

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 chunks are further reduced to smaller particles. The particles are combined with hot water to create slurry. The slurry moves through a pipeline where it separates into sand, clay and bitumen. Air is introduced to the slurry mixture, which creates a 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, referred to as dilbit , 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 hydro-treating and a hydro-conversion process to remove sulfur and break the heavy carbon molecules into lighter products. The three major products that the Scotford upgrader produces are Premium Albian synthetic crude oil, Albian Heavy synthetic crude oil and vacuum gas oil. The vacuum gas oil is sold to the operator under a long term contract at market-related prices, and the other products are sold in the marketplace.

The following table sets forth key operating statistics for the last two years.

OSM Operating Statistics

(Thousands of barrels per day)	2008	2007[(a)]
Net bitumen production[(b)]	25	4
Net synthetic crude sales	32	4

(a) The oil sands mining operations were acquired October 18, 2007. Daily volumes for 2007 represent total volumes since the acquisition date over total days in the period.

(b) Bitumen production is before royalties.

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Proved reserves can be added as expansions are permitted, funding is approved and certain stipulations of the joint venture agreement are satisfied. The following table sets forth changes in estimated quantities of net proved bitumen reserves for the year 2008.

Estimated Quantities of Proved Bitumen Reserves

(Millions of barrels)	2008
Beginning of year	421
Revisions[(a)]	(30)
Extensions, discoveries and additions	6
Production	(9)
End of year	388

(a) Revisions were driven primarily by price and the impact of the new royalty regime discussed below.

The above estimated quantity of net proved bitumen reserves is a forward-looking statement and is based on a number of assumptions, including (among others) commodity prices, volumes in-place, presently known physical data, recoverability of bitumen, industry economic conditions, levels of cash flow from operations, and other operating considerations. To the extent these assumptions prove inaccurate, actual recoveries could be different than current estimates. For a discussion of the proved bitumen reserves estimation process, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Estimates Estimated Net Recoverable Reserve Quantities Proved Bitumen Reserves. Operations at the AOSP are not within the scope of Statement of Financial Accounting Standards (SFAS) No. 25, Suspension of Certain Accounting Requirements for Oil and Gas Producing Companies (an Amendment of Financial Accounting Standards Board (FASB) Statement No. 19), SFAS No. 69, Disclosures about Oil and Gas Producing Activities (an Amendment of FASB Statements 19, 25, 33 and 39), and Securities and Exchange Commission (SEC) Rule 4-10 of Regulation S-X; therefore, bitumen production and reserves are not included in our Supplementary Information on Oil and Gas Producing Activities. The SEC has recently issued a release amending these disclosure requirements effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Accounting Standards Not Yet Adopted for additional information.

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, expansion of treatment facilities at the existing Muskeg River mine, expansion of the Scotford upgrader and development of related infrastructure, is anticipated to begin operations in late 2010 or 2011. When Expansion 1 is complete, we will have more than 50,000 bpd of net production and upgrading capacity in the Canadian oil sands. The timing and scope of future expansions and debottlenecking opportunities on existing operations remain under review.

During 2008, the Alberta government accepted the project s application to have a portion of the Expansion 1 capital costs form part of the Muskeg River mine s allowable cost recovery pool. Due to commodity price declines in the year, royalties for 2008 were one percent of the gross mine revenue.

Commencing January 1, 2009, the Alberta Royalty regime has been amended such that royalty rates will be based on the Canadian dollar (CAD) equivalent monthly average West Texas Intermediate (WTI) price. Royalty rates will rise from a minimum of one percent to a maximum of nine percent under the gross revenue method and from a minimum of 25 percent to a maximum of 40 percent under the net revenue method. Under both methods, the minimum royalty is based on a WTI price of $55.00 CAD per barrel and below while the maximum royalty is reached at a WTI price of $120.00 CAD per barrel and above, with a linear increase in royalty between the aforementioned prices.

The above discussion of the Oil Sands Mining segment includes forward-looking statements concerning the anticipated completion of AOSP Expansion 1. 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.

Refining, Marketing and Transportation

Refining

We own and operate seven refineries in the Gulf Coast, Midwest and upper Great Plains regions of the United States with an aggregate refining capacity of 1.016 million barrels per day (mmbpd) of crude oil. During 2008,

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our refineries processed 944 mbpd of crude oil and 207 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, 2008.

Crude Oil Refining Capacity

(Thousands of barrels per day)	2008
Garyville, Louisiana	256
Catlettsburg, Kentucky	226
Robinson, Illinois	204
Detroit, Michigan	102
Canton, Ohio	78
Texas City, Texas	76
St. Paul Park, Minnesota	74
TOTAL	1,016

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 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 intermediate products between refineries to optimize operations, produce higher margin products and utilize our processing capacity efficiently.

Our Garyville, Louisiana, refinery is located along the Mississippi River in southeastern Louisiana. The Garyville refinery processes heavy sour crude oil into products such as gasoline, distillates, sulfur, asphalt, propane, polymer grade propylene, isobutane and coke. In 2006, we approved an expansion of our Garyville refinery by 180 mbpd to 436 mbpd, with a currently projected cost of $3.35 billion (excluding capitalized interest). Construction commenced in early 2007 and is continuing on schedule. We estimate that, as of December 31, 2008, this project is approximately 75 percent complete. We expect to complete the expansion in late 2009.

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 the southeastern Illinois town of Robinson. 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.

Our Detroit, Michigan, refinery is located near Interstate 75 in southwest Detroit. 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 our Detroit, Michigan, refinery, with a current projected cost of $2.2 billion (excluding capitalized interest). This project will enable the refinery to process additional heavy sour crude oils, including Canadian bitumen blends, and will increase its crude oil refining capacity by about 15 percent. Construction began in the first half of 2008 and is presently expected to be complete in mid-2012.

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 St. Paul Park, a suburb of Minneapolis-St. Paul. The St. Paul Park refinery processes predominantly Canadian crude oils into products such as gasoline, diesel, jet fuel, kerosene, asphalt, propane, propylene and sulfur.

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The above discussion includes forward-looking statements concerning the expansion of the Garyville refinery and the Detroit refinery heavy oil upgrading and expansion project. Some factors that could affect those projects include transportation logistics, availability of materials and labor, unforeseen hazards such as weather conditions, delays in obtaining or conditions imposed by necessary government and third-party approvals and other risks customarily associated with construction projects.

Planned maintenance activities requiring temporary shutdown of certain refinery operating units, or turnarounds, are periodically performed at each refinery. We performed major turnaround activities at our Robinson, Catlettsburg, Garyville and Canton refineries in 2008, at our Catlettsburg, Robinson and St. Paul Park refineries in 2007 and at our Catlettsburg refinery in 2006.

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)	2008	2007	2006
Gasoline	609	646	661
Distillates	342	349	323
Propane	22	23	23
Feedstocks and special products	96	108	107
Heavy fuel oil	24	27	26
Asphalt	75	86	89
TOTAL	1,168	1,239	1,229

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, 27 mbpd, or 5 percent, was supplied by a combination of our E&P and OSM production operations for the year 2008.

Sources of Crude Oil Refined

(Thousands of barrels per day)	2008	2007	2006
United States	466	527	470
Canada	135	138	130
Middle East and Africa	244	253	266
Other international	99	92	114
TOTAL	944	1,010	980
Average cost of crude oil throughput *(Dollars per barrel)*	$ 98.34	$ 71.20	$ 61.15

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 product marketing and distribution We are a supplier of refined products to resellers and consumers within our 23-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 65 light product and 22 asphalt terminals. In addition, we distribute through 68 third-party terminals in our market area. Our marine transportation operations include 15 towboats and 196 owned and 5 leased barges that transport refined products on the Ohio, Mississippi and Illinois rivers, their tributaries and the Intercoastal Waterway. We lease or own 2,500 railcars of various sizes and capacities for movement and storage of refined products and over 140 transport trucks.

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	2008	2007	2006
Private-brand marketers, commercial and industrial consumers	67%	69%	71%
Marathon-branded outlets	18%	16%	14%
Speedway SuperAmerica LLC (SSA) retail outlets	15%	15%	15%

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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)	2008	2007	2006
Gasoline	756	791	804
Distillates	375	377	375
Propane	22	23	23
Feedstocks and special products	100	103	106
Heavy fuel oil	23	29	26
Asphalt	76	87	91
TOTAL[(a)]	1,352	1,410	1,425
Average sales price *(Dollars per barrel)*	$ 109.49	$ 86.53	$ 77.76

(a) Includes matching buy/sell volumes of 24 mbpd in 2006. On April 1, 2006, we changed our accounting for matching buy/sell arrangements as a result of a new accounting standard. This change resulted in lower refined products sales volumes for 2008, 2007 and the remainder of 2006 than would have been reported under our previous accounting practices. See Note 2 to the consolidated financial statements.

Gasoline and distillates We sell gasoline, gasoline blendstocks and No. 1 and No. 2 fuel oils (including kerosene, jet fuel, diesel fuel and home heating oil) to wholesale marketing customers in the Midwest, upper Great Plains, Gulf Coast and southeastern regions of the United States. We sold 47 percent of our gasoline volumes and 88 percent of our distillates volumes on a wholesale or spot market basis in 2008. 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 fuel ethanol into gasoline for over 15 years and began increasing our blending program in 2007, in part due to federal regulations that require us to use specified volumes of renewable fuels. We blended 57 mbpd of ethanol into gasoline in 2008, 41 mbpd in 2007 and 35 mbpd in 2006. 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.

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.

Propane 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.

Feedstocks and special products 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 2,700 tons per day of fuel grade coke at the Garyville refinery, which is used for power generation and in miscellaneous industrial applications. In September 2008, we shut down our lubes facility in Catlettsburg, Kentucky, and sold from inventory through December 31, 2008; therefore, base oils, aromatic extracts and slack wax are no longer being produced and marketed. In addition, we have recently discontinued production and sales of petroleum pitch and aliphatic solvents.

Heavy fuel oil We produce and market heavy oil, also known as fuel oil, residual fuel or slurry at all seven of our refineries. Another product of crude oil, heavy oil is primarily used in the utility and ship bunkering (fuel) industries, though there are other more specialized uses of the product. We also sell heavy fuel oil at our terminals in Wellsville, Ohio, and Chattanooga, Tennessee.

Asphalt We have refinery based asphalt production capacity of up to 102 mbpd. We market asphalt through 33 owned or leased terminals throughout the Midwest and Southeast. We have a broad customer base, including

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approximately 710 asphalt-paving contractors, government entities (states, counties, cities and townships) and asphalt roofing shingle manufacturers. We also produce asphalt cements, polymerized asphalt, asphalt emulsions and industrial asphalts.

Retail Marketing

SSA, our wholly-owned subsidiary, 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. As of December 31, 2008, SSA had 1,617 retail outlets in nine states. Sales of refined products through these retail outlets accounted for 15 percent of our refined product sales volumes in 2008. Revenues from sales of non-petroleum merchandise through these retail outlets totaled $2,838 million in 2008, $2,796 million in 2007 and $2,706 million in 2006. The demand for gasoline is seasonal in a majority of SSA markets, usually with the highest demand during the summer driving season. Profit levels from the sale of merchandise and services tend to be less volatile than profit levels from the retail sale of gasoline and diesel fuel.

In October 2008, we sold our interest in Pilot Travel Centers LLC (PTC), an operator of travel centers in the United States.

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 1,815 miles of crude oil lines and 1,826 miles of refined product lines comprising 34 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 11 percent of the crude oil and refined product shipments on our MPL and ORPL common carrier pipelines in 2008. 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)	2008	2007	2006
Crude oil trunk lines	1,405	1,451	1,437
Refined products trunk lines	960	1,049	1,101
TOTAL	2,365	2,500	2,538

We also own 176 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 3,000 miles of refined products pipelines, including about 800 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 lines include the 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.

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In addition, as of December 31, 2008, 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 crude oil lines run from: Patoka, Illinois, to Catlettsburg, Kentucky; Patoka, Illinois, to Robinson, Illinois; Patoka, Illinois, to Lima, Ohio; Samaria, Michigan, to Detroit, Michigan; and St. James, Louisiana, to Garyville, Louisiana.

In addition, as of December 31, 2008, 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;
- 37 percent interest in the Capline system, a large-diameter crude oil pipeline extending from St. James, Louisiana, to Patoka, Illinois;
- 26 percent undivided ownership 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.

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.

LNG Operations

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 and delivered its first cargo of LNG. LNG from the production facility is sold

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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. Sales of LNG from this production facility totaled 3.4 metric tonnes in 2008. In 2008 we continued discussions with the government of Equatorial Guinea and 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 contract with two of Japan s largest utility companies, with 2008 LNG deliveries totaling 40 gross bcf. In June 2008 we, along with our partner, received approval from the DOE to extend the export license for this natural gas liquefaction plant through March 2011.

In April 2004, we began delivering LNG cargoes at the Elba Island, Georgia, LNG regasification terminal pursuant to an LNG sales and purchase agreement. Under the terms of the agreement, we have the right to deliver and sell up to 58 bcf of natural gas (as LNG) per year, through March 31, 2021, with a possible extension to November 30, 2023. In September 2004, we signed an agreement under which we will be supplied with 58 bcf of natural gas per year, as LNG, for a minimum period of five years. The agreement allows for delivery of LNG at the Elba Island LNG regasification terminal with pricing linked to the Henry Hub index. This supply agreement enables us to fully utilize our rights at Elba Island during the period of this agreement, while affording us the flexibility to commercialize other stranded natural gas resources beyond the term of this contract. The agreement commenced in 2005.

Methanol Operations

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. Sales of methanol from the plant totaled 792,794 metric tonnes in 2008. Production from the plant is used to supply customers in Europe and the United States.

Natural Gas Technology

We are developing a range of natural gas conversion technologies that can connect stranded natural gas to both conventional and transportation fuel markets. Our proprietary Gas-to-Fuels (GTF) process offers the ability to convert natural gas into premium fuels while bypassing conventional intermediate synthetic gasification technology. The base patent for this technology was awarded in 2007.

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.

Also, during 2008, we completed construction of a facility to demonstrate operation of the fully integrated GTF process at a practical scale. We are evaluating the commercialization of this technology and have engaged an engineering contractor to provide engineering and design services for using the GTF technology on a commercial scale.

In addition to GTF, we continue to evaluate the application of other natural gas technologies, including LNG technology enhancements, gas hydrates and gas-to-liquids technology.

The above discussion of the Integrated Gas segment contains forward-looking statements with respect to the possible expansion of the LNG production facility and expectations for a GTF demonstration 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. Factors that could potentially affect the GTF demonstration facility include construction delays, start-up difficulties relating to scale-up in the process and unforeseen difficulties in our testing program related to moving from laboratory to practical scale. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

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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 2008 Global Upstream Performance Review published by IHS Herold Inc., we rank ninth among U.S.-based petroleum companies on the basis of 2007 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 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 2009 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, 2008. We compete in four distinct markets for the sale of refined products wholesale, spot, branded and retail distribution. We believe we compete with about 45 companies in the sale of refined products to wholesale marketing customers, including private-brand marketers and large commercial and industrial consumers; about 70 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 280 retailers in the retail sale of refined products. (A jobber is a business who does not carry out refining operations, but who supplies refiner-branded products to gasoline stations or convenience stores. Dealers refer to a retail service station or convenience store operator, 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. In recent years, several nontraditional fuel retailers, such as supermarkets, club stores and mass merchants, have affected the convenience store industry with their entrance into the retail transportation fuel business.

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 and Safety organization has the responsibility to ensure that our operating organizations maintain environmental compliance systems that are in accordance 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, composed primarily of senior management, which oversees the response to any major emergency, environmental or other incident involving us or any of our properties.

Legislation and regulations pertaining to climate change and greenhouse gas emissions have the potential to impact us. The Kyoto Protocol, effective in 2005, has been ratified by countries in which we have or in the future may have operations. Canadian federal and provincial laws, the U.S. Energy Independence and Security Act of 2007, the European Union requirements and California laws contain provisions related to greenhouse gas emissions. Other climate change legislation and regulations in the United States, Canada and abroad are in various stages of development or implementation. These regulations are further along in development in Alberta, Canada, and in the European Union, where we have significant operations. Our industry and businesses

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throughout the United States are also awaiting the U.S. Environmental Protection Agency s (EPA) actions upon the remand of the U.S. Supreme Court decision in Massachusetts v. USEPA, which could have impacts on a number of air permitting and environmental regulatory programs. In July 2008, the EPA issued an Advanced Notice of Proposed Rulemaking (ANPR) to address the Supreme Court decision and to seek public input on potential actions it may take to regulate greenhouse gas emissions. Action by EPA on the ANPR is expected in 2009. There also is other pending litigation which could affect whether EPA regulates greenhouse gas emissions. In addition, a new Administration in the U.S. may choose to address greenhouse gas emissions through regulation, permitting or other action in 2009. Our liquid hydrocarbon, natural gas and bitumen 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 the transportation of crude oil and refined products. Although there may be adverse financial impact (including compliance costs, potential permitting delays and potential reduced demand for crude oil or certain refined products) associated with any legislation, regulation, EPA or other action, the extent and magnitude of that impact cannot be reliably or accurately estimated due to the fact that requirements have only recently been adopted and the present uncertainty regarding the additional measures and how they will be implemented. Private party litigation has also been brought against emitters of greenhouse gas emissions, but we have not been named in those cases. As part of our commitment to environmental stewardship, we estimate and publicly report greenhouse gas emissions from our operations. We are working to continuously improve the accuracy and completeness of these estimates. In addition, we continuously strive to improve operational and energy efficiencies through resource and energy conservation where practicable and cost effective.

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

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 $120 million between 2006 and 2008, and plan to spend approximately $50 million in 2009 on refinery investments to produce ultra-low sulfur diesel fuel for off-road use, in compliance with EPA regulations. Further, we have estimated that we may spend approximately $1 billion over a five-year period beginning in 2008 to comply with Mobile Source Air Toxics II (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 $76 million through December 31, 2008 and we expect to spend $200 million in 2009. The cost estimates are forward-looking statements and are subject to change as further work is completed in 2009.

The EPA is in the process of implementing regulations to address current National Ambient Air Quality Standards (NAAQS) for fine particulate emissions and ozone. In connection with these standards, the EPA will designate certain areas as nonattainment, meaning that the air quality in such areas does not meet the NAAQS. To address these nonattainment areas, the EPA proposed a rule in 2004 called the Interstate Air Quality Rule (IAQR) that would require significant emissions reductions in numerous states. The final rule, promulgated in 2005, was renamed the Clean Air Interstate Rule (CAIR). While the EPA expects that states will meet their

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

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 2011, Canada will implement a ban on the land application of certain wastes, and we are developing options to treat or dispose of these wastes consistent with these new restrictions. Ongoing waste handling and disposal-related costs, however, are not expected to be material.

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

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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 issued a directive which more clearly defines criteria for managing oil sands tailings. The AOSP Joint Venture Parties are reviewing this directive to determine the impact on the oil sands operations and the timeline for the required compliance. Increased compliance costs may result if tailing pond reclamation technologies prove unsuccessful or the directive requires additional measures.

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 multiple-part Renewable Fuel Standard (RFS). The RFS was 9.0 billion gallons of renewable fuel in 2008, and is 11.1 billion gallons in 2009, increasing to 36.0 billion gallons by 2022. In the near term, the RFS will be satisfied primarily with fuel ethanol blended into gasoline. The RFS presents production and logistic challenges for both the fuel ethanol and petroleum refining industries. The RFS has required, and may 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 RFS, EISA establishes an advanced biofuel RFS that begins with 0.6 billion gallons in 2009 and increases to 21.0 billion gallons by 2022. Subsets within the advanced biofuel RFS include 0.5 billion gallons of biomass-based diesel in 2009, increasing to 1.0 billion gallons in 2012, and 0.1 billion gallons of cellulosic biofuel in 2010, increasing to 16.0 gallons by 2022. 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.

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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. The agreement also obligates us to use commercially reasonable efforts to obtain and maintain letters of credit and other liquidity arrangements required under 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 significant 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 30,360 active employees as of December 31, 2008. Of that number, 19,794 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. Negotiations are currently underway with the same union in Texas

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City with a contract expiration of March 31, 2009. 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, 2009, are as follows:

Clarence P. Cazalot, Jr.	58	President and Chief Executive Officer
Janet F. Clark	54	Executive Vice President and Chief Financial Officer
Gary R. Heminger	55	Executive Vice President, Downstream
Steven B. Hinchman	50	Executive Vice President, Technology and Services
Jerry Howard	60	Senior Vice President, Corporate Affairs
Paul C. Reinbolt	53	Vice President, Finance and Treasurer
David E. Roberts	48	Executive Vice President, Upstream
William F. Schwind, Jr.	64	Vice President, General Counsel and Secretary
Michael K. Stewart	51	Vice President, Accounting and Controller
Howard J. Thill	49	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 and chief financial officer effective January 2005. Ms. Clark joined Marathon in January 2004 as senior vice president and chief financial officer.

Mr. Heminger was appointed executive vice president, downstream effective January 2005. Mr. Heminger has served as president of MPC since September 2001.

Mr. Hinchman was appointed senior vice president, worldwide production effective January 2002 and was appointed to his current position effective April 1, 2008.

Mr. Howard was appointed senior vice president, corporate affairs effective January 2002.

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. Schwind was appointed vice president, general counsel and secretary effective January 2002.

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 the 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.

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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 bitumen 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 bitumen reserves.

The proved liquid hydrocarbon and natural gas reserves information included in this report has been derived from engineering estimates. Those estimates were prepared by our in-house teams of reservoir engineers and geoscience professionals and reviewed, on a selected basis, by our Corporate Reserves Group or third-party consultants we have retained. The estimates were calculated using liquid hydrocarbon and natural gas prices in effect as of December 31, 2008, as well as other conditions in existence as of that date. Any significant future price

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changes will have a material effect on the quantity and present value of our proved liquid hydrocarbon and natural gas reserves. Future reserve revisions could also result from changes in, among other things, governmental regulation and severance and other production taxes.

Proved liquid hydrocarbon and natural gas reserve estimation is a subjective process that involves estimating volumes to be recovered from underground accumulations of liquid hydrocarbons and natural gas that cannot be directly measured. Estimates of economically recoverable liquid hydrocarbon and natural gas 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;
- the assumed effects of regulation by governmental agencies; and
- assumptions concerning future operating costs, severance and excise taxes, development costs and workover and repair costs.

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

- the amount and timing of liquid hydrocarbon and natural gas 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 and natural gas reserves reflected in this report should not be considered as the market value of the reserves attributable to our liquid hydrocarbon and natural gas properties. As required by SEC Rule 4-10 of Regulation S-X, the estimated discounted future net revenues from our proved liquid hydrocarbon and natural gas reserves are based on prices and costs as of 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.

The proved bitumen reserves information included in this report has also been derived from engineering estimates. Reserves related to mining operations are defined as that part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination. Proved reserves are measured by various testing and sampling methods. Bitumen reserves as of December 31, 2008 were estimated by third-party consultants, using volumetric estimation techniques similar to those used in estimating liquid hydrocarbon and natural gas reserves and are subject to many of the same uncertainties discussed above, except that estimates of bitumen reserves are based on average annual prices consistent with industry practice in Canada. The estimated quantity of net proved bitumen reserves is based on a number of assumptions, including (among others) commodity prices, volumes in-place, presently known physical data, recoverability of bitumen, industry economic conditions, levels of cash flow from operations and other operating considerations. To the extent these assumptions prove inaccurate, actual recoveries could be different than current estimates. Future proved bitumen reserve revisions could also result from changes in, among other things, governmental regulation and taxation.

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

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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 and regulations relating to the protection of the environment, including those relating to the discharge of materials into the environment, waste management, pollution prevention measures, 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 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 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 could result in civil 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) operate and maintain our facilities, (2) install new emission controls at our refineries and other facilities and (3) administer and manage any potential greenhouse gas emissions or carbon tax program. 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.

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

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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, or 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.

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.

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 multiple-part Renewable Fuel Standard (RFS). The RFS was 9.0 billion gallons of renewable fuel in 2008, and is 11.1 billion gallons in 2009, increasing to 36.0 billion gallons by 2022. In the near term, the RFS will be satisfied primarily with fuel ethanol blended into gasoline. The RFS presents production and logistics challenges for both the fuel ethanol and petroleum refining industries. The RFS has required, and may in the future continue to require, additional capital expenditures or expenses by us to accommodate increased fuel ethanol use. 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 per gallon or due to refined petroleum products being replaced by renewable fuels. In addition, tax incentives and other subsidies have made renewable fuels more competitive with refined products than they otherwise would have been which may have reduced and may further reduce refined product margins and refined products ability to compete with renewable fuels.

The recent distress 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 business insurance coverage, cash management services, commercial letters of credit and short-term investments. The recent distress affecting the financial markets and the possibility that financial institutions may consolidate or go bankrupt has reduced levels of activity in the credit markets. This could diminish the amount of financing available to companies. In addition, such turmoil in the financial markets could significantly increase our costs associated with borrowing. Our liquidity and our ability to access the credit or capital markets may also be adversely affected by changes in the financial markets and the global economy. Continuing turmoil in the financial markets could make it more difficult for us to access capital, sell assets, refinance our existing indebtedness, enter into agreements for new indebtedness or obtain funding through the issuance of our securities. In addition, there could be a number of follow-on effects from the credit crisis on us, including insolvency of customers, key suppliers and other counterparties to our commodity and foreign exchange derivative instruments.

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

Local political and economic factors in international markets could have a material adverse effect on us. A total of 63 percent of our liquid hydrocarbon and natural gas sales volumes in 2008 was derived from production outside the United States and 70 percent of our proved liquid hydrocarbon and natural gas reserves as of December 31, 2008, were located outside the United States. All of our bitumen 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 international markets, including changes in foreign governmental policies relating to liquid hydrocarbon, natural gas, bitumen 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 foreign 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.

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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, and we do not insure against all potential losses and therefore we could be seriously harmed by unexpected liabilities.

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. 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. Certain 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 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 or 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.

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.

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If Ashland fails to pay its taxes, we could be responsible for satisfying various tax obligations of Ashland.

As a result of the transactions in which we acquired the minority interest in MPC from Ashland in 2005, Marathon is severally liable for federal income taxes (and in some cases for certain state taxes) of Ashland for tax years still open as of the date we completed the transactions. We have entered into a tax matters agreement with Ashland, which provides that:

- We will be responsible for the tax liabilities of the Marathon group of companies, including the tax liabilities of MPC and the other companies and businesses we acquired in the transactions (for periods after the completion of the transactions); and

- Ashland will generally be responsible for the tax liabilities of the Ashland group of companies before the completion of the transactions, and the income taxes attributable to Ashland s interest in MPC before the completion of the transactions. However, under certain circumstances we will have several liability for those tax liabilities owed by Ashland to various taxing authorities, including the Internal Revenue Service.

If Ashland fails to pay any tax obligation for which we are severally liable, we may be required to satisfy this tax obligation. That would leave us in the position of having to seek indemnification from Ashland. In that event, our indemnification claims against Ashland would constitute general unsecured claims, which would be effectively subordinate to the claims of secured creditors of Ashland, and we would be subject to collection risk associated with collecting unsecured debt from Ashland.

We are required to pay Ashland for deductions relating to various contingent liabilities of Ashland, which could be material.

We are required to claim tax deductions for certain contingent liabilities that will be paid by Ashland after completion of the transactions. Under the tax matters agreement, we are required to pay the benefit of those deductions to Ashland, with the computation and payment terms for such tax benefit payments divided into two baskets, as described below:

Basket One This applies to the first $30 million of contingent liability deductions (increased by inflation each year up to a maximum of $60 million) that we may claim in each year for the first 20 years following the acquisition. The benefit of Basket One deductions is determined by multiplying the amount of the deduction by 32 percent (or, if different, by a percentage equal to three percentage points less than the highest federal income tax rate during the applicable tax year). We are obligated to pay this amount to Ashland. The computation and payment of Basket One amounts does not depend on our ability to generate actual tax savings from the use of the contingent liability deductions in Basket One. Upon specified events related to Ashland (or after 20 years), the contingent liability deductions that would otherwise have been compensated under Basket One will be taken into account in Basket Two. In addition, Basket One applies only for federal income tax purposes; state, local or foreign tax benefits attributable to specified liability deductions will be compensated only under Basket Two.

Because we are required to make payments to Ashland whether or not we generate any actual tax savings from the Basket One contingent liability deductions, the amount of our tax benefit payments to Ashland with respect to Basket One contingent liability deductions may exceed the aggregate tax benefits that we derive from these deductions. We are obligated to make these payments to Ashland even if we do not have sufficient taxable income to realize any benefit for the deductions.

Basket Two All contingent liability deductions relating to Ashland s pre-transactions operations that are not subject to Basket One are considered and compensated under Basket Two. The benefit of Basket Two deductions is determined on a with and without basis; that is, the contingent liability deductions are treated as the last deductions used by the Marathon group. Thus, if the Marathon group has deductions, tax credits or other tax benefits of its own, it will be deemed to use them to the maximum extent possible before it will be deemed to use the contingent liability deductions. To the extent that we have the capacity to use the contingent liability deductions based on this methodology, the actual amount of tax saved by the Marathon group through the use of the contingent liability deductions will be calculated and paid to Ashland. Because Basket Two amounts are calculated based on the actual tax saved by the Marathon group from the use of Basket Two deductions, those amounts are subject to recalculation in the event there is a change in the Marathon group s tax liability for a particular year. This could occur because of audit adjustments or carrybacks of losses or credits from other years, for example. To the extent that such a recalculation results in a smaller Basket Two benefit with respect to a contingent liability deduction for which Ashland has already received compensation, Ashland is required to repay

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such compensation to Marathon. In the event we become entitled to any repayment, we would be subject to collection risks associated with collecting an unsecured claim from Ashland.

If the transactions resulting in our acquisition of the minority interest in MPC that was 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 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 may 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.

Under the laws of most states, a transaction could be held to be constructively fraudulent if a court determined that:

- the transferor received less than reasonably equivalent value or, in some jurisdictions, less than fair consideration or valuable consideration ; and
- the transferor:
  - was insolvent at the time of the transfer or was rendered insolvent by the transfer;
  - was engaged, or was about to engage, in a business or transaction for which its remaining property constituted unreasonably small capital; or
  - intended to incur, or believed it would incur, debts beyond its ability to pay as those debts matured.

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. In order to help establish that Ashland received reasonably equivalent value or fair consideration from us in the transactions, we obtained a written opinion from a nationally recognized appraisal firm to the effect that Ashland received amounts that were reasonably equivalent to the combined value of Ashland s interest in MPC and the other assets we acquired. We also obtained a favorable opinion from that appraisal firm relating to various financial tests that supported our conclusion and Ashland s representation to us that Ashland was not insolvent either before or after giving effect to the closing of the transactions. Those opinions were based on specific information provided to the appraisal firm and were subject to various assumptions, including assumptions relating to Ashland s existing and contingent liabilities and insurance coverage. Although we are confident in our conclusions regarding (1) Ashland s receipt of reasonably equivalent value or fair consideration and (2) Ashland s solvency, it should be noted that the valuation of any business and a determination of the solvency of any entity involve numerous assumptions and uncertainties, and it is possible that a court could disagree with our conclusions.

If United States Steel fails to perform any of its material obligations to which we have financial exposure, we could be required to pay those obligations, and any such payment could materially reduce our cash flows and profitability and impair our financial condition.

In connection with the separation of United States Steel from Marathon, United States Steel agreed to hold Marathon harmless from and against various liabilities. While we cannot estimate some of these liabilities, the portion of these liabilities that we can estimate amounts to $513 million as of December 31, 2008, including accrued interest of $8 million. If United States Steel fails to satisfy any of those obligations, we would be required to satisfy them and seek indemnification from United States Steel. In that event, our indemnification claims against United States Steel would constitute general unsecured claims, effectively subordinate to the claims of secured creditors of United States Steel.

The steel business is highly competitive and a large number of industry participants have sought protection under bankruptcy laws in the past. The enforceability of our claims against United States Steel could become subject to the effect of any bankruptcy, fraudulent conveyance or transfer or other law affecting creditors rights generally, or of general principles of equity, which might become applicable to those claims or other claims arising from the facts and circumstances in which the separation was effected.

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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 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 those 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.

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 and 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 and natural gas sales volumes and net bitumen production volumes are set forth in Item 8. Financial Statements and Supplementary Data Supplemental Statistics. Estimated net proved liquid hydrocarbon and natural gas 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 and estimated net proved bitumen reserves are set forth in Item 1. Business Oil Sands Mining. The basis for estimating these reserves is discussed in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Estimates Estimated Net Recoverable Reserve Quantities Proved Liquid Hydrocarbon and Natural Gas Reserves and Proved Bitumen 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 are a defendant, along with other refining companies, in 20 cases arising in three states alleging damages for methyl tertiary-butyl ether (MTBE) contamination. We have also received seven Toxic Substances Control Act notice letters involving potential claims in two states. Such notice letters are often followed by litigation. Like the cases that were settled in 2008, the remaining MTBE cases are consolidated in a multidistrict litigation in the Southern District of New York for pretrial proceedings. Nineteen of the remaining cases allege damages to water

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supply wells, similar to the damages claimed in the settled cases. In the other remaining case, the State of New Jersey is seeking natural resources damages allegedly resulting from contamination of groundwater by MTBE. This is the only MTBE contamination case in which we are a defendant and natural resources damages are sought. We are vigorously defending these cases. We, along with a number of other defendants, have engaged in settlement discussions related to the majority of the cases in which we are a defendant. We do not expect our share of liability, if any, for the remaining cases to significantly impact our consolidated results of operations, financial position or cash flows.

Natural Gas Royalty Litigation

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

Product Contamination Litigation

A lawsuit filed in the United States District Court for the Southern District of West Virginia alleges 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 we deny that any permanent damages resulted from the incident. Class action certification was granted in August 2007. We have entered into a tentative settlement agreement in this case. Notice of the proposed settlement has been sent to the class members. Approval by the court after a fairness hearing is required before the settlement can be finalized. The fairness hearing is scheduled in the first quarter of 2009. The proposed settlement will 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. Mediation has been unsuccessful and the parties expect the Court to set a briefing schedule for summary judgment motions.

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 pending litigation with U.S. EPA in Wyoming Federal District Court.

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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 State seeks penalties above $100,000. We continue to work with the state in an effort to resolve this matter.

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. The state seeks penalties above $100,000. We continue to work with the state in an effort to resolve the matter.

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.

Other Environmental Proceedings

The following is a summary of proceedings involving us that were pending or contemplated as of December 31, 2008, 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, 2008, we had been identified as a PRP at a total of nine CERCLA waste sites and we may be a PRP at four additional sites where we have received information requests or other indications but we do not have sufficient information to establish liability. We are at various stages of case development at the nine PRP sites with some site information being preliminary and incomplete and subject to change, but we currently estimate our liability will be under $200,000 at four sites, under $1 million at one site, under $2 million at two sites, and under $4 million at the remaining two sites.

There are also 119 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

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incomplete, we believe that liability for clean-up and remediation costs in connection with six of these sites will be under $100,000 per site, that 58 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. There are 16 of these sites for which 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 nearly $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 28 years, we anticipate spending approximately $4.8 million in remediation costs at this site. In 2009, 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 2008 and 2007 were $434,000 and $524,000, respectively, with expenditures for remedial measures in 2009 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 2008.

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 $1.1 million, as part of a settlement of an enforcement action for alleged CAA violations relating to benzene waste NESHAPS. We hope to enter into a formal consent decree or amendment to resolve these matters in 2009.

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 agreed order seeking $143,000 in penalties. We hope to resolve this matter with the TCEQ in 2009.

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 and Texas City refineries with agreed to penalties of $321,500 and $135,000 imposed in Canton (2007) and Texas City (2008), respectively. No penalties were imposed as a result of the other inspections. Inspections at St. Paul Park (2009) and Garyville (2010) may occur 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. Subject to entering a formal consent decree to memorialize our understanding, we have agreed with the U.S. EPA to pay a civil penalty of $118,000. We hope to enter into a formal consent decree to resolve these matters in 2009.

SEC Investigation Relating to Equatorial Guinea

By letter dated July 15, 2004, the SEC notified us that it was conducting an inquiry into payments made to the government of Equatorial Guinea, or to officials and persons affiliated with officials of the government of Equatorial Guinea. By letter dated February 13, 2009, the SEC further notified us that they completed their investigation and did not intend to recommend any enforcement action in this matter.

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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. 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.

As of January 31, 2009, there were 57,275 registered holders of Marathon common stock.

Information concerning the quarterly high and low sales prices for Marathon common stock follows:

	2008		2007[(a)]	
	High	Low	High	Low
Quarter 1	$ 61.88	$ 45.23	$ 102.56	$ 83.43
Quarter 2	55.05	44.92	132.51	59.74
Quarter 3	52.78	37.48	65.04	49.24
Quarter 4	38.81	19.58	62.59	53.34

(a) Prices are as published each day; therefore, those before June 18, 2007 do not reflect the two-for-one stock split.

Recent Sales of Unregistered Securities

In October 2007, we issued 29,127,260 shares of Marathon common stock to Western shareholders in connection with our acquisition of Western. This issuance of Marathon common stock was exempt from the registration requirements of the Securities Act of 1933, as amended, by virtue of Section 3(a)(10).

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.

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Issuer Purchases of Equity Securities

The following table provides information about purchases by Marathon and its affiliated purchaser during the quarter ended December 31, 2008, of equity securities that are registered by Marathon pursuant to Section 12 of the Securities Exchange Act of 1934:

Period	Column (a) Total Number of Shares Purchased[(a)(b)]	Column (b) Average Price Paid per Share	Column (c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[(d)]	Column (d) Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs[(d)]
10/01/08 10/31/08	27,687	$ 38.24		$ 2,080,366,711
11/01/08 11/30/08	24,957	$ 29.22		$ 2,080,366,711
12/01/08 12/31/08	11,040[(c)]	$ 24.26		$ 2,080,366,711
Total	63,684	$ 32.28		

(a) 63,672 shares of restricted stock were delivered by employees to Marathon, upon vesting, to satisfy tax withholding requirements.

(b) Under the terms of the transactions whereby we acquired the minority interest in MPC and other businesses from Ashland, Marathon paid Ashland shareholders cash in lieu of issuing fractional shares of Marathon s common stock to which such holders would otherwise be entitled. We acquired 12 shares due to acquisition share exchanges and Ashland share transfers pending at the closing of the transaction.

(c) The Marathon Oil Corporation Dividend Reinvestment and Direct Stock Purchase Plan (the Dividend Reinvestment Plan) was temporarily suspended effective December 1, 2008, and remains suspended. No purchases of Marathon common stock to satisfy the requirements for dividend reinvestment were made by the administrator of the Dividend Reinvestment Plan after November 30, 2008. The determination to suspend the Dividend Reinvestment Plan was due to the evaluation of the separation of our businesses as described in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Evaluation of Separation of Marathon s Businesses.

(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, 2008, 66 million split adjusted common shares had been acquired at a cost of $2,922 million, which includes transaction fees and commissions that are not reported in the table above. No share repurchases were made in the fourth quarter of 2008.

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Item 6. Selected Financial Data

(Dollars in millions, except as noted)	2008[a]	2007[b][c]	2006	2005[d]	2004
Statement of Income Data:					
Revenues[e]	$ 77,193	$ 64,552	$ 64,896	$ 62,986	$ 49,465
Income from continuing operations	3,528	3,948	4,957	3,006	1,294
Net income	3,528	3,956	5,234	3,032	1,261
Basic per share data:					
Income from continuing operations	$ 4.97	$ 5.72	$ 6.92	$ 4.22	$ 1.92
Net income	$ 4.97	$ 5.73	$ 7.31	$ 4.26	$ 1.87
Diluted per share data:					
Income from continuing operations	$ 4.95	$ 5.68	$ 6.87	$ 4.19	$ 1.91
Net income	$ 4.95	$ 5.69	$ 7.25	$ 4.22	$ 1.86
Statement of Cash Flows Data:					
Capital expenditures from continuing operations	$ 7,146	$ 4,466	$ 3,433	$ 2,796	$ 2,141
Dividends paid	681	637	547	436	348
Dividends per share	$ 0.96	$ 0.92	$ 0.76	$ 0.60	$ 0.51
Balance Sheet Data as of December 31:					
Total assets	$ 42,686	$ 42,746	$ 30,831	$ 28,498	$ 23,423
Total long-term debt, including capitalized leases	7,087	6,084	3,061	3,698	4,057

(a) Includes a $1,412 million impairment of goodwill related to the OSM reporting unit, (see Note 16 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 14 to the consolidated financial statements).

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

(c) 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.

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

(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. See Note 2 to the consolidated financial statements.

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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 U.S., Canada, 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 by-products.

- 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.

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

Certain sections of Management s Discussion and Analysis of Financial Condition and Results of Operations include forward-looking statements concerning trends or events potentially affecting our business. These statements typically contain words such as anticipates, believes, estimates, expects, targets, plans, projects, could, may, should, would or similar words indicating that future outcomes are uncertain. In accord 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.

Evaluation of Separation of Marathon s Businesses

On July 31, 2008, we announced that our board of directors would be evaluating the separation of Marathon into two independent, publicly-traded companies, each focused on its own set of business opportunities. On February 3, 2009, we further announced that our board concluded it is in the best interest of our shareholders to remain a fully integrated energy company.

Overview

Exploration and Production

Prevailing prices for the various qualities of crude oil and natural gas that we produce significantly impact our revenues and cash flows. Prices were extremely volatile in 2008 with the following table listing high and low spot prices during the year for key benchmarks.

Benchmark	High	Date	Low	Date
WTI crude oil *(Dollars per barrel)*	$ 145.29	July 3	$ 33.87	December 19

Brent crude oil *(Dollars per barrel)*	$ 144.22	July 3	$ 33.66	December 24
Henry Hub natural gas *(Dollars per mcf)*[(a)]	$ 13.11	July 1	$ 6.47	November 1

(a) First-of-month price index.

On average, crude oil prices in 2008 were higher than in 2007. Crude oil prices climbed rapidly through the first half of 2008 based upon expected strong global demand, a declining dollar, ongoing concerns about supplies of

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crude oil, and political unrest in the Middle East and elsewhere. Later in 2008, crude oil prices dropped more rapidly than they had climbed as the U.S. dollar rebounded and other countries entered recessions which decreased demand.

During 2008, the average spot price per barrel for WTI was $99.75, up from an average of $72.41 in 2007, but ended the year at $44.60. The average spot price per barrel for Brent was $97.26 in 2008, up from an average of $72.39 in 2007, but ended the year at $36.55. The differential between WTI and Brent average prices widened to $2.49 in 2008 from $0.02 in 2007. Our domestic crude oil production is on average heavier and higher in sulfur content than light sweet WTI. Heavier and higher sulfur crude oil (commonly referred to as heavy sour crude oil) sells at a discount to light sweet crude oil. Our international crude oil production is relatively sweet and is generally sold in relation to the Brent crude oil benchmark.

Natural gas prices on average were higher in 2008 than in 2007. A significant portion of our U.S. lower 48 states natural gas production is sold at bid-week prices or first-of-month indices relative to our specific producing areas. The average Henry Hub first-of-month price index was $2.18 per thousand cubic feet (mcf) higher in 2008 than the 2007 average. Natural gas sales in Alaska are subject to term contracts. Our other major natural gas-producing regions are Europe and Equatorial Guinea, where large portions of our natural gas sales are subject to term contracts, making realized prices in these areas less volatile. As we sell larger quantities of natural gas from these regions, to the extent that these fixed prices are lower than prevailing prices, our reported average natural gas prices realizations may decrease.

E&P segment income during 2008 was up 57 percent from 2007, with revenue increases tied to these increases in average commodity prices accounting for almost half of the income improvement. Liquid hydrocarbon and natural gas sales volumes were also higher in 2008 than 2007.

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 upgrader. During 2008, our average realized price for synthetic crude oil and vacuum gas oil was $91.90 per barrel, up from 2007, but ended the year at $24.97 per barrel impacted by a heavier yield in December and a seasonal decrease in the value of our heavy output.

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 benchmark prices that impact both our revenues and variable costs, listing high and low spot prices during the year.

Benchmark	High	Date	Low	Date
WTI crude oil *(Dollars per barrel)*	$ 145.29	July 3	$ 33.87	December 19
Western Canadian Select *(Dollars per barrel)*[(a)]	$ 114.95	July	$ 23.18	December
AECO natural gas sales index *(Canadian dollars per gigajoule)*[(b)]	$ 11.34	July 1	$ 5.42	September 19

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

(b) Alberta Energy Company day ahead index.

Our OSM segment reported income of $258 million for 2008, reflecting synthetic crude oil and vacuum gas oil sales averaging 32 mboepd. Derivative instruments intended to hedge price risk on future sales have impacted revenues in the periods presented, with net gains of $48 million in 2008 and net losses of $53 million in 2007. In the first quarter of 2009, we entered into derivative instruments which effectively offset certain of our open derivative positions.

Refining, Marketing and Transportation

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

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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 an indicator of the impact of price on the refining margin. Crack spreads can fluctuate significantly, particularly when prices of refined products do not move in the same relationship as the cost of crude oil. As a performance benchmark and a comparison with other industry participants, we calculate Midwest (Chicago) and U.S. Gulf Coast crack spreads that we feel most closely track our operations and slate of products. Posted Light Louisiana Sweet (LLS) prices and a 6-3-2-1 ratio of products (6 barrels of crude oil producing 3 barrels of gasoline, 2 barrels of distillate and 1 barrel of residual fuel) are used for the crack spread calculation. The following table lists calculated average crack spreads by quarter for the Midwest (Chicago) and Gulf Coast markets in 2008.

Crack spreads

(Dollars per barrel)	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	2008
Chicago LLS 6-3-2-1	$ 0.07	$ 2.71	$ 7.81	$ 2.31	$ 3.27
US Gulf Coast LLS 6-3-2-1	$ 1.39	$ 1.99	$ 6.32	($ 0.01)	$ 2.45

In addition to the market changes indicated by the crack spreads, our refining and wholesale marketing gross margin is impacted by factors such as the types of crude oil and other charge and blendstocks processed, the selling prices realized for refined products, the impact of commodity derivative instruments used to mitigate price risk and the cost of purchased products for resale. We process significant amounts of sour crude oil which can enhance our profitability compared to certain of our competitors, as sour crude oil typically can be purchased at a discount to sweet crude oil. Finally, our refining and wholesale marketing gross margin is impacted by changes in manufacturing costs, which are primarily driven by the level of maintenance activities at the refineries and the price of purchased natural gas used for plant fuel.

Our 2008 refining and wholesale marketing gross margin was the key driver of the 43 percent decrease in RM&T segment income when compared to 2007. Our average refining and wholesale marketing gross margin per gallon decreased 37 percent, to 11.66 cents in 2008 from 18.48 cents in 2007, primarily due to the significant and rapid increases in crude oil prices early in 2008 and lagging wholesale price realizations.

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. While on average demand has been increasing for several years, 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. In 2008, demand began to drop due to the combination of significant increases in retail petroleum prices and a broad slowdown in general activity. The gross margin on merchandise sold at retail outlets has historically been more constant.

The profitability of our pipeline transportation operations is primarily dependent on the volumes shipped through our crude oil and refined products pipelines. The volume of crude oil that we transport is directly affected by the supply of, and refiner demand for, crude oil in the markets served directly by our crude oil pipelines. Key factors in this supply and demand balance are the production levels of crude oil by producers, the availability and cost of alternative modes of transportation, and refinery and transportation system maintenance levels. The volume of refined products that we transport is directly affected by the production levels of, and user demand for, refined products in the markets served by our refined product pipelines. In most of our markets, demand for gasoline peaks during the summer and declines during the fall and winter months, whereas distillate demand is more ratable throughout the year. As with crude oil, other transportation alternatives and system maintenance levels influence refined product movements.

Integrated Gas

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

Our most significant LNG investment is our 60 percent ownership in a production facility in Equatorial Guinea, which sells LNG under a long-term contract at prices tied to Henry Hub natural gas prices. In 2008, its

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first full year of operations, the plant sold 3.4 million metric tonnes. Our share of sales was 2.1 million tonnes. Industry estimates of 2008 LNG trade are approximately 175 million metric tonnes, which is about 25 percent of international natural gas trade. More LNG production facilities and tankers are being constructed. The recent worldwide economic downturn is 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. Sales of methanol from the plant totaled 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 2008 Chemical Markets Associates, Inc. s World Methanol Analysis predicts demand for methanol in 2009 will be 43 million metric tonnes. Our plant capacity is 1.1 million, or 3 percent of total demand. Also included in the financial results of the Integrated Gas segment are costs associated with ongoing development of integrated gas projects, including natural gas technology research.

Integrated Gas segment income in 2008 was up 129 percent from 2007, primarily because the LNG production facility in Equatorial Guinea, which commenced operations in May 2007, operated for the full year.

2008 Operating Highlights

E&P

- We added net proved liquid hydrocarbon and natural gas reserves of 110 million barrels of oil equivalent (boe), excluding dispositions of 3 million boe, while producing 137 million boe during 2008. Over the past three years, we have added net proved reserves of 344 million boe, excluding dispositions of 48 million boe, while producing 396 million boe.

- We completed the operated Alvheim/Vilje development offshore Norway, with first production from Alvheim in June 2008 and from Vilje in July 2008.

- We completed the outside-operated Neptune development in deepwater Gulf of Mexico, which began producing in July 2008.

- We drilled a second appraisal well on the Droshky prospect in deepwater Gulf of Mexico and received Board approval to develop the prospect.

- We announced a successful discovery well on the Gunflint prospect in deepwater Gulf of Mexico.

- We were awarded 15 blocks at Outer Continental Shelf Lease Sale No. 206, and a second Indonesian offshore exploration block.

- We announced the Portia and Dione discoveries on deepwater Angola Block 31, bringing our total discoveries in Angola to 28.

- We received government approval to proceed with the first development project on Angola Block 31.

The Volund development offshore Norway continues to progress on schedule toward first production in late 2009 and will be tied back to the Alvheim infrastructure.

RM&T

We have completed approximately 75 percent of our Garyville, Louisiana, refinery expansion, which is scheduled to start-up in the fourth quarter of 2009.

We commenced construction of the Detroit refinery heavy oil upgrading and expansion project, with start-up expected in mid-2012.

OSM

Expansion 1 at the Athabasca Oil Sands Project (AOSP) continues to proceed on schedule.

Divestitures

We sold our 50-percent ownership in the Pilot Travel Centers LLC (PTC) joint venture in a $700 million transaction.

We sold our non-core outside-operated assets and associated undeveloped acreage in the Heimdal area offshore Norway for proceeds of $301 million.

We reached an agreement to sell our producing assets in Ireland.

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Consolidated Results of Operations: 2008 compared to 2007

Revenues are summarized in the following table.

(In millions)	2008	2007
E&P	$ 12,486	$ 9,155
OSM	1,122	221
RM&T	64,481	56,075
IG	93	218
Segment revenues	78,182	65,669
Elimination of intersegment revenues	(1,207)	(885)
Gain (loss) on U.K. gas contracts	218	(232)
Total revenues	$ 77,193	$ 64,552
Items included in both revenue and costs and expenses:		
Consumer excise taxes on petroleum products and merchandise	$ 5,065	$ 5,163

E&P segment revenues increased $3,331 million in 2008 from 2007. 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.

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E&P Operating Statistics	2008	2007
Net Liquid Hydrocarbon Sales *(Thousands of barrels per day)*[a]		
United States	63	64
Europe[b]	55	33
Africa[b]	93	100
Total International[b]	148	133
WORLDWIDE	211	197
Net Natural Gas Sales *(Millions of cubic feet per day)*[c][d]		
United States	448	477
Europe	198	216
Africa	370	232
Total International	568	448
WORLDWIDE	1,016	925
Total Worldwide Sales *(Thousands of barrels of oil equivalent per day)*	381	351
Average Realizations[e]		
Liquid Hydrocarbons *(Dollars per barrel)*		
United States	$ 86.68	$ 60.15
Europe	90.60	70.31
Africa	90.29	66.09
Total International	90.40	67.15
WORLDWIDE	$ 89.29	$ 64.86
Natural Gas *(Dollars per thousand cubic feet)*		
United States	$ 7.01	$ 5.73
Europe	8.03	6.53
Africa	0.25	0.25
Total International	2.97	3.28
WORLDWIDE	$ 4.75	$ 4.54

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

(b) Represents equity tanker lifting and direct deliveries of liquid hydrocarbons. The amounts correspond with the basis for fiscal settlements with governments. Crude oil purchases, if any, from host governments are excluded.

(c) Represents net sales after royalties, except for Ireland where amounts are before royalties.

(d) Includes natural gas acquired for injection and subsequent resale of 32 mmcfd and 47 mmcfd in 2008 and 2007.

(e) 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 United Kingdom that are accounted for as derivative instruments.

OSM segment revenues totaled $1,122 million in 2008 and $221 million in 2007, 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 in 2008 from 2007. 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 in 2008 from 2007. 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.

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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 $10,713 million in 2008 from 2007. 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 16 to the consolidated financial statements for further information about the impairment.

Net interest and other financial income or costs reflected $50 million in costs for 2008 and $41 million of income for 2007, an unfavorable change of $91 million from 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 $544 million in 2008 from 2007, a 19 percent increase, although income from continuing operations before income taxes increased only $124 million, or 2 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 $252 million benefit from the remeasurement of foreign currency denominated deferred taxes to U.S. dollars. The following is an analysis of the effective income tax rates for continuing operations for 2008 and 2007. See Note 12 to the consolidated financial statements.

	2008	2007
Statutory U.S. income tax rate	35.0%	35.0%
Effects of foreign operations, including foreign tax credits	16.7	9.8
Effects of nondeductible goodwill impairment	7.1	
Adjustments to valuation allowances	(9.6)	
State and local income taxes, net of federal income tax effects	1.3	2.0
Effects of enacted changes in tax laws		(2.8)
Other tax effects	(1.1)	(1.6)
Effective income tax rate for continuing operations	49.4%	42.4%

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Segment Results: 2008 compared to 2007

Segment income or loss 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	1,846	1,106
E&P segment income	2,715	1,729
OSM	258	(63)
RM&T	1,179	2,077
IG	302	132
Segment income	4,454	3,875
Items not allocated to segments, net of income taxes:		
Corporate and other unallocated items	(93)	(122)
Gain (loss) on U.K. natural gas contracts[(a)]	111	(118)
Foreign currency gain on income taxes	252	18
Impairments[(b)]	(1,437)	
Gain on dispositions	241	8
Gain on foreign currency derivative instruments		112
Deferred income taxes tax legislation changes		193
Loss on early extinguishment of debt		(10)
Net income	$ 3,528	$ 3,956

(a) Amounts relate to natural gas contracts in the United Kingdom that are accounted for as derivative instruments and recorded at fair value. See Critical Accounting Estimates Fair Value Estimates.

(b) Impairments include a $1,412 million impairment of goodwill related to the OSM reporting unit (see Note 16 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 14 to the consolidated financial statements).

United States E&P income increased $246 million, or 39 percent, in 2008 from 2007. 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 $740 million, or 67 percent, in 2008 from 2007, 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 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.

RM&T segment income decreased $898 million in 2008 from 2007, 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 no longer use derivatives to mitigate domestic crude oil acquisition price risk. For

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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 effect Hurricane Gustav and Ike had on U.S. Gulf Coast 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 (including transportation), purchased products and manufacturing expenses, including depreciation.

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.

Consolidated Results of Operations: 2007 compared to 2006

Revenues are summarized in the following table.

(In millions)	2007	2006
E&P	$ 9,155	$ 9,010
OSM	221	
RM&T	56,075	55,941
IG	218	179
Segment revenues	65,669	65,130
Elimination of intersegment revenues	(885)	(688)
Gain (loss) on long-term U.K. gas contracts	(232)	454
Total revenues	$ 64,552	$ 64,896
Items included in both revenue and costs and expenses:		
Consumer excise taxes on petroleum products and merchandise	$ 5,163	$ 4,979
Matching crude oil and refined product buy/sell transactions settled in cash:		
E&P		16
RM&T	127	5,441
Total buy/sell transactions included in revenues	$ 127	$ 5,457

E&P segment revenues increased $145 million in 2007 from 2006. The 2007 increase was primarily related to increased international crude oil marketing activities. Higher liquid hydrocarbon realized prices were not sufficient to offset the impact of sales volume declines as illustrated in the table below. Both liquid hydrocarbon and natural gas sales volumes from domestic operations decreased in 2007 primarily due to normal production declines in the Gulf of Mexico and Permian Basin, while international liquid hydrocarbon sales volumes were lower primarily because our Libya sales returned to normal levels compared to 2006, which included volumes owed to our account upon the resumption of our operations there. While international natural gas sales volumes increased, the majority of the increase was due sales to EGHoldings LNG production facility in Equatorial Guinea that began operations in the second quarter of 2007. This increase in fixed-price sales volumes also contributed to the decline in our average international natural gas realizations. Our share of the income ultimately generated by the subsequent export of LNG produced by EGHoldings, as well as methanol produced by AMPCO is reflected in our Integrated Gas segment as discussed below.

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E&P Operating Statistics	2007	2006
Net Liquid Hydrocarbon Sales *(Thousands of barrels per day)*[a]		
United States	64	76
Europe[b]	33	35
Africa[b]	100	112
Total International[b]	133	147
Worldwide Continuing Operations	197	223
Discontinued Operations[c]		12
WORLDWIDE	197	235
Net Natural Gas Sales *(Millions of cubic feet per day)*[d][e]		
United States	477	532
Europe	216	243
Africa	232	72
Total International	448	315
WORLDWIDE	925	847
Total Worldwide Sales *(Thousands of barrels of oil equivalent per day)*		
Continuing Operations	351	365
Discontinued Operations		12
WORLDWIDE	351	377
Average Realizations[f]		
Liquid Hydrocarbons *(Dollars per barrel)*		
United States	$ 60.15	$ 54.41
Europe	70.31	64.02
Africa	66.09	59.83
Total International	67.15	60.81
Worldwide Continuing Operations	64.86	58.63
Discontinued Operations		38.38
WORLDWIDE	$ 64.86	$ 57.58
Natural Gas *(Dollars per thousand cubic feet)*		
United States	$ 5.73	$ 5.76
Europe	6.53	6.74
Africa	0.25	0.27
Total International	3.28	5.27
WORLDWIDE	$ 4.54	$ 5.58

(a) Includes crude oil, condensate and natural gas liquids.
(b) Represents equity tanker lifting and direct deliveries of liquid hydrocarbons. The amounts correspond with the basis for fiscal settlements with governments. Crude oil purchases, if any, from host governments are excluded.
(c) Represents our Russian oil exploration and production businesses that were sold in June 2006.
(d) Represents net sales after royalties, except for Ireland where amounts are before royalties.
(e) Includes natural gas acquired for injection and subsequent resale of 47 mmcfd and 46 mmcfd in 2007 and 2006.
(f) 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 $15 million in 2007 and gains of $25 million in 2006. Excluded from E&P segment revenues were losses of $232 million in 2007 and gains of $454 million in 2006 related to natural gas sales contracts in the United Kingdom that are accounted for as derivative instruments. See Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

OSM segment revenues totaled $221 million in 2007, reflecting sales for the period subsequent to the October 18, 2007, Western acquisition date. Revenues during this period were reduced by $53 million of unrealized losses on derivative instruments held by Western at the acquisition date intended to mitigate price risk related to future sales of synthetic crude oil. Revenues were also negatively impacted by a mid-November fire and the subsequent curtailment of operations at the Scotford upgrader. Maintenance work originally scheduled for the first quarter of 2008 was performed in conjunction with the necessary repairs. The Scotford upgrader returned to operation in late December.

RM&T segment revenues increased $134 million in 2007 from 2006, while the portion related to matching buy/sell transactions decreased $5,314 million. Matching buy/sell transactions arise from arrangements in which we agree to buy a specified quantity and quality of crude oil or refined product to be delivered to a specified location

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while simultaneously agreeing to sell a specified quantity and quality of the same commodity at a specified location to the same counterparty. Prior to April 1, 2006, all matching buy/sell transactions were recorded as separate sale and purchase transactions, or on a gross basis. For contracts entered into on or after April 1, 2006, the income effects of matching buy/sell transactions are reported in cost of revenues, or on a net basis. Transactions under contracts entered into before April 1, 2006 continued to be reported on a gross basis until their termination. This accounting change had no effect on net or segment income but the amounts of revenues and cost of revenues recognized after April 1, 2006 are less than the amounts that would have been recognized under previous accounting practices.

The decrease in revenues from matching buy/sell transactions was a result of the change in accounting for these transactions effective April 1, 2006, discussed above. Excluding matching buy/sell transactions, 2007 revenues increased primarily as a result of higher refined product prices.

Income from equity method investments increased $154 million in 2007 from 2006. Income from the LNG production facility in Equatorial Guinea accounts for most of the increase for 2007, as it began operations in May 2007 and delivered 24 cargoes during the year.

Cost of revenues increased $6,689 million in 2007 from 2006. The increase was primarily in the RM&T segment and resulted from increases in acquisition costs of crude oil, refinery charge and blendstocks and purchased refined products. The increase was also impacted by higher manufacturing expenses, primarily planned maintenance projects, or turnarounds, in 2007.

Purchases related to matching buy/sell transactions decreased $5,247 million in 2007 from 2006 as a result of the change in accounting for matching buy/sell transactions discussed above.

Depreciation, depletion and amortization increased $95 million in 2007 from 2006. The increase in 2007 primarily relates to the addition of the Oil Sands Mining assets recorded as a result of the Western acquisition, increased accretion of asset retirement obligations associated with international E&P properties and increased depreciation related to various refinery improvements in 2006 and 2007, such as our low-sulfur diesel projects.

Selling, general and administrative expenses increased $99 million in 2007 from 2006. The 2007 expense increases were primarily because personnel and staffing costs increased throughout the year as a result of variable compensation arrangements and increased business activity. Contingency accruals also contributed to the 2007 increase.

Exploration expenses increased $89 million in 2007 from 2006. Exploration expenses related to dry wells and other write-offs totaled $233 million and $166 million in 2007 and 2006.

Net interest and other financial income or costs reflected $41 million of income for 2007, a favorable change of $4 million from 2006. Included in net interest and other financial income or costs were foreign currency transaction gains of $2 million and $16 million for 2007 and 2006.

Gain on foreign currency derivative instruments in 2007 represents 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 decreased $1,121 million in 2007 from 2006 primarily due to the $2,130 million decrease in income from continuing operations before income taxes. The decrease in our effective income tax rate in 2007 was primarily a result of the $193 million benefit of applying the Canadian income tax rate reductions enacted subsequent to our acquisition of Western to the applicable net deferred tax liabilities. These tax rates will decrease from 32 percent to 25 percent by 2012. The following is an analysis of the effective income tax rates for continuing operations for 2007 and 2006. See Note 12 to the consolidated financial statements.

	2007	2006
Statutory U.S. income tax rate	35.0%	35.0%
Effects of foreign operations, including foreign tax credits	9.8	10.1
State and local income taxes, net of federal income tax effects	2.0	1.9
Effects of enacted changes in tax laws	(2.8)	(0.2)

Other tax effects	(1.6)	(2.0)
Effective income tax rate for continuing operations	42.4%	44.8%

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Discontinued operations related to the exploration and production businesses which were sold in June 2006. After-tax gains on the disposal of $8 million and $243 million were also included in discontinued operations for 2007 and 2006. See Note 8 to the consolidated financial statements.

Segment Results: 2007 compared to 2006

As discussed in Note 8 to the consolidated financial statements, we sold our Russian oil exploration and production businesses during 2006. The activities of these operations have been reported as discontinued operations and therefore are excluded from segment results for all periods presented.

Segment income or loss for 2007 and 2006 is summarized and reconciled to net income in the following table.

(In millions)	2007	2006
E&P		
United States	$ 623	$ 873
International	1,106	1,130
E&P segment income	1,729	2,003
OSM	(63)	
RM&T	2,077	2,795
IG	132	16
Segment income	3,875	4,814
Items not allocated to segments, net of income taxes:		
Corporate and other unallocated items	(122)	(190)
Gain (loss) on U.K. natural gas contracts[a]	(118)	232
Foreign currency gain (loss) on income taxes	18	(22)
Gain on dispositions	8	274
Gain on foreign currency derivative instruments	112	
Deferred income taxes tax legislation changes	193	21
other adjustments[b]		93
Loss on early extinguishment of debt	(10)	(22)
Discontinued operations		34
Net income	$ 3,956	$ 5,234

(a) Amounts relate to natural gas contracts in the United Kingdom that are accounted for as derivative instruments and recorded at fair value. See Critical Accounting Estimates Fair Value Estimates.

(b) Other deferred tax adjustments in 2006 represent a benefit recorded for cumulative income tax basis differences associated with prior periods.

United States E&P income decreased $250 million, or 29 percent, in 2007 from 2006. The decrease was primarily due to the revenue decline discussed above. In addition, exploration expenses were $105 million higher in 2007 than in 2006, primarily as a result of expensing non-commercial wells on the Flathead prospect in the Gulf of Mexico in 2007.

International E&P income decreased $24 million in 2007 from 2006. The revenue decrease associated with lower liquid hydrocarbon sales volumes discussed above had the most significant impact on pretax income.

OSM segment loss totaled $63 million in 2007, reflecting results for the period subsequent to the October 18, 2007, Western acquisition date. This loss includes a $40 million after-tax unrealized loss on derivative instruments held by Western at the acquisition date intended to mitigate price risk related to future sales of synthetic crude oil. Segment income was also impacted by a mid-November fire and subsequent curtailment of operations at the Scotford upgrader. Maintenance work originally scheduled for the first quarter of 2008 was performed in conjunction with the necessary repairs. The Scotford upgrader returned to operation in late December.

RM&T segment income decreased $718 million in 2007 from 2006, primarily a result of a decrease in our refining and wholesale marketing gross margin per gallon from 22.88 cents in 2006 to 18.48 cents in 2007. Though the market-based crack spreads for 2007 were stronger than in 2006, our refining and wholesale marketing gross margin declined primarily due to the significant and rapid increase in our crude oil costs during 2007, including the impact of derivatives, and lagging wholesale price realizations. Our refining and marketing wholesale gross margin was further reduced by higher manufacturing costs related to planned maintenance at several refineries. In addition to the lower refining and wholesale gross margin, segment income was impacted by higher operating and administrative expenses.

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Included in the refining and wholesale marketing gross margins were pretax derivative losses of $899 million in 2007 and gains of $400 million in 2006. 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 1,010 mbpd of crude oil throughput in 2007 and 980 mbpd in 2006. Our reported crude oil refining capacity increased to 1,016 mbpd in 2007 from 974 mbpd in 2006 due to overall efficiency gains in the operation of the refining units, reflecting the cumulative effect of regular maintenance, capital improvements and other process optimization efforts.

The following table includes certain key operating statistics for the RM&T segment for 2007 and 2006.

RM&T Operating Statistics	2007	2006
Refining and wholesale marketing gross margin *(Dollars per gallon)*[a]	$ 0.1848	$ 0.2288
Refined products sales volumes *(Thousands of barrels per day)*	1,410	1,425

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

IG segment income increased $116 million in 2007 from 2006. During 2007, construction of the LNG production facility in Equatorial Guinea was completed ahead of schedule and on budget. The increase in 2007 segment income over the previous year was largely due to the facility beginning operations in May 2007 and delivering 24 cargoes during the year. Additionally, income from our equity method investment in AMPCO was higher in 2007 on increased methanol production due to plant downtime in 2006 and higher realized prices in 2007. In 2006, a $17 million pretax loss was recognized as a result of the renegotiation of a technology agreement and income from our equity method investment in AMPCO was lower due to plant downtime during a planned turnaround and subsequent compressor repair.

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

Cash Flows

Net cash provided from operating activities totaled $6,782 million in 2008, compared to $6,521 million in 2007 and $5,488 million in 2006. The $261 million increase in 2008 primarily reflects the impact of higher average realized prices. The $1,033 million increase in 2007 primarily reflects working capital changes partially offset by lower net income.

Net cash used in investing activities totaled $5,435 million in 2008, compared with $8,102 million in 2007 and $2,955 million in 2006. Significant investing activities include capital expenditures, acquisitions of businesses and asset disposals.

Capital expenditures by segment for continuing operations for each of the last three years are summarized in the following table.

(In millions)	2008	2007	2006
E&P			
United States	$ 2,036	$ 1,354	$ 1,302
International	1,077	1,157	867
Total E&P	3,113	2,511	2,169
OSM	1,038	165	
RM&T	2,954	1,640	916
IG	4	93	307
Corporate	37	57	41
Total	$ 7,146	$ 4,466	$ 3,433

Capital expenditures for multiple years are impacted by the following projects. In our E&P segment, development and completion of the Alvheim/Vilje project affected our capital expenditures in 2006, 2007 and to a lesser extent in 2008. Similarly, our Angola exploration and development projects impacted all three years. In our RM&T segment, the expansion of our Garyville, Louisiana refinery commenced with front-end engineering and design (FEED) in 2006 followed by construction in 2007 and 2008. Also in RM&T, the expansion and upgrading

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of our Detroit, Michigan refinery commenced with FEED in 2007 and construction in 2008. Integrated gas spending in 2006 and through May 2007 reflects the completion of the LNG production facility in Equatorial Guinea.

New capital spending in 2008 was primarily related to the ongoing AOSP Expansion 1 in the OSM segment, and in U.S. exploration and development projects primarily in the Gulf of Mexico.

Acquisitions in 2007 consist primarily 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. In 2006, acquisitions primarily included cash payments of $718 million associated with our re-entry into Libya.

Disposal of assets totaled $999 million, $137 million and $134 million in 2008, 2007 and 2006. 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. Disposal of assets included proceeds from the sale of our interests in two LNG tankers in Alaska in 2007 and proceeds from the sale of 90 percent of our interest in Syrian natural gas fields in 2006. Disposals for all years included proceeds from the sale of various domestic producing properties and SSA stores.

Disposal of discontinued operations of $832 million in 2006 related to the sale of our Russian exploration and production businesses in June 2006. See Note 8 to the consolidated financial statements.

Net cash used in financing activities totaled $1,193 million in 2008, compared with net cash provided by financing activities of $184 million in 2007 and cash used in financing activities of $2,581 million in 2006. Sources of cash in 2008 included the issuance of $1.0 billion in senior notes. Sources of cash in 2007 included the issuance of $1.5 billion in senior notes and borrowings of $578 million from the Norwegian export credit agency. Significant uses of cash in financing activities in all years were common stock repurchases under our share repurchase plan, dividend payments and debt repayments.

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, are held in trust to be disbursed to us upon our request for reimbursement of expenditures related to our Garyville, Louisiana refinery expansion. Through December 31, 2008, such reimbursements have totaled $1,032 million. The $1.0 billion obligation is reflected as long-term debt and the remaining $16 million of trusteed funds, including interest income earned to date, is reflected as other noncurrent assets in the consolidated balance sheet as of December 31, 2008.

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, 2008, we had $7,087 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+ (outlook stable), Baa1 (outlook stable), and BBB+ (outlook negative). 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, 2008, 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.

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Effective April 3, 2008, we amended our revolving credit facility, extending the termination date on $2,625 million from May 2012 to May 2013. The remaining $375 million continues to have a termination date of May 2012. No single lender holds more than 10 percent of the $3.0 billion revolving credit facility.

On March 12, 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.

Subsequent to year end 2008, on February 17, 2009, we issued $700 million aggregate principal amount of senior notes bearing interest at 6.5 percent with a maturity date of February 15, 2014 and $800 million aggregate principal amount of senior notes bearing interest at 7.5 percent with a maturity date of February 15, 2019. Interest on both issues is payable semi-annually beginning August 15, 2009.

Asset Sales

In 2008, we commenced a review of our portfolio of assets with the intent of monetizing those assets which are either mature or otherwise non-strategic. Through December 31, 2008, net proceeds of $999 million have been received from the sale of assets identified in this review.

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 22 percent at December 31, 2008 and 2007. This includes $485 million of debt that is serviced by United States Steel.

(Dollars in millions)	2008	2007
Long-term debt due within one year	$ 98	$ 1,131
Long-term debt	7,087	6,084
Total debt	$ 7,185	$ 7,215
Cash	$ 1,285	$ 1,199
Trusteed funds from revenue bonds[(a)]	$ 16	$ 744
Equity	$ 21,409	$ 19,223
Calculation:		
Total debt	$ 7,185	$ 7,215
Minus cash	1,285	1,199
Minus trusteed funds from revenue bonds	16	744
Total debt minus cash	5,884	5,272
Total debt	7,185	7,215
Plus equity	21,409	19,223
Minus cash	1,285	1,199
Minus trusteed funds from revenue bonds	16	744
Total debt plus equity minus cash	$ 27,293	$ 24,495
Cash-adjusted debt-to-capital ratio	22%	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 will be disbursed to us upon our request for reimbursement of expenditures related to the Garyville refinery expansion. The trusteed funds are reflected as other noncurrent assets in the accompanying consolidated balance sheet as of December 31, 2008 and 2007.

Capital Requirements

Capital Spending

We have approved a capital, investment and exploration budget of $5,738 million for 2009, which represents a 24 percent decrease from our 2008 spending. Additional details related to the 2009 budget are discussed in Outlook Capital, Investment and Exploration Budget.

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Other Significant Expected Cash Outflows

We plan to make contributions of up to $439 million to our pension plans during 2009. As of December 31, 2008, $98 million of our long-term debt is due in the next twelve months.

Dividends of $0.96 per common share or $681 million were paid during 2008. On February 2, 2009, our Board of Directors declared a dividend of $0.24 cents per share on Marathon common stock, payable March 10, 2009, to stockholders of record at the close of business on February 18, 2009.

Share Repurchase Program

Since January 2006, our Board of Directors has authorized a common share repurchase program totaling $5 billion. As of December 31, 2008, 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. Factors that could affect the review of our portfolio of assets include the identification of buyers and the negotiation of acceptable prices and other terms, as well as other customary closing conditions. 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.

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Contractual Cash Obligations

The table below provides aggregated information on our consolidated obligations to make future payments under existing contracts as of December 31, 2008.

(In millions)	Total	2009	2010-2011	2012-2013	Later Years
Long-term debt (excludes interest)[(a)(b)]	$ 6,880	$ 68	$ 279	$ 1,718	$ 4,815
Sale-leaseback financing[(a)(k)]	297	14	55	44	184
Capital lease obligations[(a)(k)]	360	26	37	55	242
Operating lease obligations[(a)]	967	176	233	180	378
Operating lease obligations under sublease[(a)]	21	5	10	6	
Purchase obligations:					
Crude oil, feedstock, refined product and ethanol contracts[(c)]	9,955	8,322	662	479	492
Transportation and related contracts	1,657	430	401	223	603
Contracts to acquire property, plant and equipment	4,070	1,949	1,242	389	490
LNG terminal operating costs[(d)]	153	13	25	25	90
Service and materials contracts[(e)]	1,567	379	442	205	541
Unconditional purchase obligations[(f)]	50	8	14	14	14
Commitments for oil and gas exploration (non-capital)[(g)]	21	19	2		
Total purchase obligations	17,473	11,120	2,788	1,335	2,230
Other long-term liabilities reported in the consolidated balance sheet[(h)]	3,562	500	704	871	1,487
Total contractual cash obligations[(i)(j)]	$ 29,560	$ 11,909	$ 4,106	$ 4,209	$ 9,336

(a) Upon the USX Separation, United States Steel assumed certain debt and lease obligations, including $415 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 $426 million for 2009, $842 million for 2010-2011, $646 million for 2012-2013 and $3,603 million for the remaining years for a total of $5,517 million. Of these, we anticipate cash payments for interest of $23 million for 2009, $45 million for 2010-2011, $32 million for 2012-2013 and $207 million for the later years to be made by United States Steel.

(c) The majority of these contractual obligations as of December 31, 2008, relate to contracts to be satisfied within the first 180 days of 2009. 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 2018. Also includes certain tax obligations recorded in accordance with FIN 48.

(i) Includes $497 million of contractual cash obligations that have been assumed by United States Steel. See 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 $ 965 million. See Note 21 to the consolidated financial statements.

(k) During the interim period between lease inception and effective date, long-term debt costs equal estimated or reported construction costs as of the end of the reporting period, not the minimum lease payment/rentals.

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.

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We have provided various guarantees related to equity method investees, United States Steel and others. These arrangements are described in Note 27 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, 2007 and 2006. We believe that these transactions with related parties have been conducted under terms comparable to those with unrelated parties.

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, 2008, we have identified the following obligations that have been assumed by United States Steel:

- $415 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 $8 million at December 31, 2008. We anticipate United States Steel will make future interest payments of $23 million for 2009, $45 million for 2010-2011, $32 million for 2012-2013 and $207 million for the later years.

- $37 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, 2008.

- $32 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, 2008.

- $21 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 27 to the consolidated financial statements.

Of the total $513 million, obligations of $492 million and corresponding receivables from United States Steel were recorded on our consolidated balance sheet as of December 31, 2008, (current portion $23 million; long-term portion $469 million). The remaining $21 million was related to off-balance sheet arrangements and contingent liabilities of United States Steel.

United States Steel has restrictive covenants related to its indebtedness that could have an adverse effect on its financial position and liquidity. In its Form 10-K for the year ended December 31, 2008, United States Steel reported that it was in compliance with all debt covenants, but that the current global recession may affect its

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ability to comply with those covenant and conditions in the future. Such circumstances could trigger a need for United States Steel to modify or replace credit agreements on less favorable terms that could adversely affect its flexibility, cash flow and profitability.

Outlook

Capital, Investment and Exploration Budget

Our Board of Directors approved a capital, investment and exploration budget of $5,738 million for 2009, which includes budgeted capital expenditures of $5,547 million. This represents a 24 percent decrease from 2008 spending. The focus of our 2009 budget is to maintain solid production performance, enhance our downstream business and provide necessary investments in mid- and long-term growth projects.

The budget includes worldwide exploration and production spending of $2,468 million. A significant amount of this budget, 45 percent, is targeted on projects that will sustain and grow production in the short-term, including domestic assets such as those in the Bakken Shale and Piceance Basin and international development projects like Volund in Norway. Mid-term production growth projects such as Droshky and Ozona in the Gulf of Mexico and emerging resource plays in the Marcellus and Woodford Shales account for 34 percent of the 2009 budget. Long-term projects will require about 20 percent of budgeted funds in 2009. The PSVM development on Angola Block 31, the Gudrun development in Norway, as well as exploration in the Gulf of Mexico, Angola, Norway and Indonesia are our significant long-term projects.

The budget includes $887 million for the Oil Sands Mining segment in 2009, primarily for the continuation of Expansion 1. This is slightly lower than 2008 spending due in part to the stronger U.S. dollar and to the expected deferral of some nonessential projects.

The budget includes $1,944 million for RM&T projects, with about 52 percent budgeted for the Garyville refinery expansion and 17 percent for the Detroit refinery heavy oil upgrading and expansion project. The remainder of the budget is allocated to maintaining facilities and meeting regulatory requirements, notably the Mobile Source Air Toxics (MSAT) regulations that will be effective at the beginning of 2011.

The remaining $439 million relates to capitalized interest and corporate activities.

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.

Exploration

Major exploration activities are currently underway or under evaluation worldwide.

Angola We hold a 10 percent outside-operated interest in offshore Block 31 and a 30 percent outside-operated interest in offshore Block 32. We plan to participate in four to six exploration or appraisal wells in these deepwater blocks in 2009. Four potential development hubs have been identified on these two blocks and we continue to evaluate our discoveries for future development.

Norway We hold interests in over 510,000 acres offshore Norway and plan to continue our exploration efforts there. In 2009, exploration drilling is expected to commence on additional prospects with the potential to be tied back to the Alvheim complex.

Gulf of Mexico We plan to participate in one to three exploration wells during 2009. The exploration success on the Shenandoah prospect was announced in February 2009 by the operator. We own a 10 percent outside-operated interest in this prospect. Additional prospects have been identified in the Gulf of Mexico deepwater leases acquired in 2007 and 2008. These projects make up the core of our 2009 through 2010 Gulf of Mexico exploration drilling plans.

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Indonesia We continue to evaluate seismic data on the Pasangkayu Block offshore Indonesia and plan to start exploratory drilling there in early 2010. We are the operator of this block and hold a 70 percent interest. Evaluation of the Bone Bay Block offshore Indonesia, which we were awarded in 2008, continues with plans to collect seismic data in 2010. Exploratory drilling on this block could begin in 2011. We have a 49 percent interest in the Bone Bay Block and are the operator.

U.S. onshore We announced a discovery in the Woodford Shale in January 2009. We hold 30,000 net acres in the Woodford Shale resource play in the Anadarko Basin of Oklahoma and plan to participate in more horizontal wells in 2009. We also hold prospective acreage in two emerging shale resource plays in the U.S. In the Appalachian Basin we hold 65,000 net acres in the Marcellus Shale resource play in Pennsylvania and West Virginia. We also hold 25,000 net acres, primarily in Texas, in the Haynesville Shale resource play in North Louisiana and East Texas . Our plans call for initial drilling on some of these leases in 2009.

Equatorial Guinea We are evaluating development scenarios for the Deep Luba and Gardenia discoveries on the Alba Block, one of which includes production through the Alba field infrastructure. We own a 63 percent interest in the Alba Block and serve as operator.

Production

During 2008, several of our development projects were completed and began producing. We have approved new development projects, are evaluating others and will continue working on ongoing projects in 2009.

Angola In 2008 we received approval to proceed with this first deepwater PSVM development project. The development is comprised of the Plutao, Saturno, Venus and Marte discoveries. Key contracts were awarded and construction work commenced in the second half of 2008. A total of 48 production and injection wells are planned for the PSVM development. First production is targeted for 2012 with a design capacity of about 150,000 gross bpd

Norway Tie back of the Volund field offshore Norway to the Alvheim/Vilje production facility continues with first production expected in late 2009. We own a 65 percent interest in Volund and serve as operator. In addition, we hold a 28 percent outside-operated interest in the Gudrun field, located 120 miles off the coast of Norway, where a successful appraisal well was drilled in 2006. 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. A final investment decision is expected in 2009.

Gulf of Mexico The Droshky and Ozona developments in deepwater Gulf of Mexico were approved in 2008. Rig capacity has been secured for Droshky development drilling which is expected to begin in February 2009 with first production targeted for 2010. The project will consist of four development wells which will be tied back to the nearby third-party owned and operated Bullwinkle platform. We own a 100 percent working interest in Droshky. Ozona development on Garden Banks Block 515 will begin in 2009, with first production expected in 2011. We hold a 68 percent working interest in Ozona.

U.S. onshore We continue drilling on resource plays in the Piceance Basin of Colorado and the Williston Basin of North Dakota and eastern Montana (the Bakken shale resource play). In the Piceance Basin, drilling and production commenced in late 2007. Plans are to drill 150 wells during the next five years. More than 100 operated wells have already been drilled with plans to drill approximately 225 additional wells during the next five years.

The above discussion includes forward-looking statements with respect to anticipated future exploratory and development drilling, the possibility of developing Blocks 31 and 32 offshore Angola and the Droshky discovery in the Gulf of Mexico, the timing of production from the Neptune development, the Droshky discovery, the Alvheim/Vilje development, the Volund field and the Corrib project. 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. Except for the Neptune, Alvheim/Vilje and Volund developments, the foregoing forward-looking statements may be further affected by the inability to or delay in obtaining necessary government and third-party approvals and permits. The possible developments of the Droshky discovery and Blocks 31 and 32 offshore Angola 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.

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Oil Sands Mining

The AOSP Expansion 1 continues in 2009 and is expected to begin operations in the 2010 to 2011 timeframe. The expansion includes construction of mining and extraction facilities at the Jackpine mine, expansion of treatment facilities at the existing Muskeg River mine and expansion of the Scotford upgrader, along with construction of common infrastructure sized to support future mining expansions.

The above discussion includes forward-looking statements with respect to anticipated completion of the AOSP expansion. Factors which could affect the expansion 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 Garyville refinery expansion is expected to be completed and ready for start up in the fourth quarter of 2009. Total projected costs are now estimated to be $3.35 billion (excluding capitalized interest). This expansion will increase the refinery s crude oil throughput capacity by 180 mbpd and will enable the refinery to provide an additional 7.5 million gallons of clean transportation fuels to the market each day.

Permits were obtained and construction commenced for the heavy oil upgrading and expansion project at our Detroit, Michigan, refinery in 2008. Due to delays in the projected production from Canadian oil sands and current market conditions, we have reevaluated the project construction schedule and now plan to complete this project in mid-2012. We now forecast the project will cost $2.2 billion (excluding capitalized interest), or about 15 percent more than the original budget, due primarily to additional costs associated with the project deferral as well as a scope change that will allow the refinery to process heavier and more acidic crude oils.

Through these investment projects, we expect to more than double our coking capacity by 2012, which should lead to lower feedstock costs and increased margins. In addition, as the new units comprising the Garyville refinery expansion reach full capacity utilization, we anticipate the percentage of distillate produced to increase.

We estimate that we will spend approximately $200 million in 2009 to comply with MSAT II regulations.

The above discussion includes forward-looking statements concerning the planned expansion of the Garyville refinery, the Detroit refinery heavy oil upgrading and expansion project and MSAT II regulations compliance costs. Some factors that could affect the Garyville, 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

Our net worldwide LNG sales volumes are expected to average 5,700 to 6,400 metric tonnes per day in 2009.

We continue to invest in the development of new technologies to supply new energy sources. In 2008, we completed construction of a facility to demonstrate operation of the fully integrated gas-to-fuels process at a practical scale. We are evaluating the commercialization of this technology and have engaged an engineering contractor to provide engineering and design services for using our proprietary GTF technology on a commercial scale.

The above discussion contains forward looking statements with respect to future LNG sales and the potential commercialization of our GTF technology. Projected LNG sales volumes are based upon a number of assumptions, including unforeseen hazards such as weather conditions, acts of war or terrorist acts and government or military response thereto and other operating and economic considerations. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

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

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believe that substantially all of our competitors must comply with similar environmental laws and regulations. However, the specific impact on each competitor may vary depending on a number of factors, including the age and location of its operating facilities, marketing areas, production processes and whether it is also engaged in the petrochemical business or the marine transportation of crude oil and refined products.

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

(In millions)	2008	2007	2006
Capital	$ 421	$ 199	$ 176
Compliance			
Operating and maintenance	379	287	309
Remediation[b]	26	25	20
Total	$ 826	$ 511	$ 505

(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 six percent of capital expenditures for continuing operations in 2008, four percent in 2007 and five percent in 2006.

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 $373 million or seven percent of capital expenditures in 2009. Predictions beyond 2009 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 $426 million in 2010; 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.

For more information on environmental regulations that impact us, see Item 1. Business   Environmental Matters and Item 3. Legal Proceedings.

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.

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Estimated Net Recoverable Reserve Quantities

Proved Liquid Hydrocarbon and Natural Gas 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 and natural gas 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 liquid hydrocarbons and natural gas.

Proved reserves are the estimated quantities of liquid hydrocarbons and natural gas that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Estimates of proved reserves may change, either positively or negatively, as additional information becomes available and as contractual, operational, economic and political conditions change. During 2008, net revisions of previous estimates increased total proved reserves by 23 million boe (less than 2 percent of the beginning of the year reserve estimate).

Our estimation of net recoverable quantities of liquid hydrocarbons and natural gas is a highly technical process performed by in-house teams of reservoir engineers and geoscience professionals. All estimates prepared by these teams are made in compliance with SEC Rule 4-10(a)(2),(3) and (4) of Regulation S-X and SFAS No. 25, Suspension of Certain Accounting Requirements for Oil and Gas Producing Companies (an Amendment of Financial Accounting Standards Board (FASB) Statement No. 19), and disclosed in accordance with the requirements of SFAS No. 69, Disclosures about Oil and Gas Producing Activities (an Amendment of FASB Statements 19, 25, 33 and 39). The SEC has amended its disclosure requirements effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009 see Management s Discussion and Analysis of Financial Condition and Results of Operations Accounting Standards Not Yet Adopted for additional information. Estimates of liquid hydrocarbon and natural gas reserves are based on prices at December 31, 2008. Reserve estimates are reviewed and approved by our Corporate Reserves Group. Any change to proved reserves 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, who reports to our Chief Financial Officer. 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.

Third-party consultants are engaged to prepare independent reserve estimates for fields that comprise the top 80 percent of our total reserves over a rolling four-year period. We met this goal for the four-year period ended December 31, 2008. For 2006 and thereafter, we established a tolerance level of 10 percent for third-party reserve estimates such that the third-party consultants discontinue their estimation activities once their results are within 10 percent of our internal estimates. Should the third-party consultants initial analysis fail to reach our tolerance level, the consultants re-examine the information provided, request additional data and refine their analysis if appropriate. If, after this re-examination, the third-party consultants cannot arrive at estimates within our tolerance, we adjust our reserve estimates as necessary to achieve estimates within our tolerance level. This independent third-party reserve estimation process did not result in significant changes to our reserve estimates in 2008, 2007, or 2006.

The reserves of the Alba field in Equatorial Guinea comprise approximately 38 percent of our total proved liquid hydrocarbon and natural gas reserves as of December 31, 2008. The reserves of the next five largest asset groups the Waha concessions in Libya, the Alvheim/Vilje development offshore Norway, the Droshky development in Green Canyon Block 244 in the Gulf of Mexico, the Oregon Basin field in the Rocky Mountain area of the United States and the Foinaven development in the North Sea comprise 32 percent of our total proved liquid hydrocarbon and natural gas reserves.

Depreciation and depletion of producing liquid hydrocarbon and natural gas 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. 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 $0.47 per barrel, which would increase pretax

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income by approximately $66 million annually, based on 2008 production. 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 $0.52 per barrel and would result in a decrease in pretax income of approximately $73 million annually, based on 2008 production.

Proved Bitumen Reserves

We acquired a 20 percent outside-operated interest in the AOSP in Alberta, Canada with the acquisition of Western in October 2007. Oil sands mining operations at the AOSP are outside the scope of SFAS Nos. 25 and 69 and SEC Rule 4-10 of Regulation S-X; therefore, bitumen production and reserves are not included in our Supplementary Information on Oil and Gas Producing Activities. As discussed, the SEC has recently issued a release amending these disclosures see Management s Discussion and Analysis of Financial Condition and Results of Operations Accounting Standards Not Yet Adopted for additional information.

The estimated amount of proved bitumen reserves affects the amount and timing of costs depreciated, depleted or amortized into net income. The expected future cash flows to be generated by oil sands mining and bitumen upgrading assets used in testing oil sands mining and bitumen upgrading assets for impairment also rely, in part, on estimates of proved bitumen reserves.

Reserves related to oil sands mining operations are defined as that part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination. Proved bitumen reserves as of December 31, 2008 were based on a third-party consultant s estimate using volumetric estimation techniques similar to those used in estimating liquid hydrocarbon and natural gas reserves, except that estimates of bitumen reserves are based on annual average prices for 2008, which is believed to be consistent with industry practice in Canada.

Depreciation and depletion of most oil sands mining and bitumen upgrading assets is determined by the units-of-production method and could change with revisions to estimated proved bitumen reserves. On average, a five percent increase in estimated bitumen reserves would lower the depreciation and depletion rate by approximately $0.98 per barrel and would result in an increase in pretax income of approximately $9 million annually, based on 2008 production. On average, a five percent decrease in estimated bitumen reserves would increase the depreciation and depletion rate by approximately $0.52 per barrel and would result in a decrease in pretax income of approximately $5 million annually, based on 2008 production.

Fair Value Estimates

On January 1, 2008, we adopted SFAS No. 157 for those financial assets and liabilities recognized or disclosed at fair value in the consolidated financial statements on a recurring basis. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. It does not require us to make any new fair value measurements, but rather establishes a fair value hierarchy that prioritizes the inputs to the valuation techniques used to measure fair value. Level 1 inputs are given the highest priority in the fair value hierarchy, as they represent observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date, while Level 3 inputs are given the lowest priority, as they represent unobservable inputs that are not corroborated by market data. Valuation techniques that maximize the use of observable inputs are favored. See Note 17 of the consolidated financial statements for disclosures regarding our fair value measurements.

In February 2008, the FASB issued FASB Staff Position (FSP) FAS 157-2, Effective Date of FASB Statement No. 157, which deferred the effective date of SFAS No. 157 for one year for certain nonfinancial assets and nonfinancial liabilities. This includes impairments of goodwill, intangible assets and other long-lived assets, and initial measurement of asset retirement obligations, asset exchanges, pensions, business combinations and partial sales of proved properties.

The primary impact from the adoption of SFAS No. 157 at January 1, 2008, related to the fair value measurement of our derivative instruments. Additional information about derivatives and their valuation may be found in Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

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Significant uses of fair value measurements include:

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

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.

Impairment Assessments of Goodwill and Long-Lived Assets

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. A significant amount of judgment is involved performing these fair value estimates for goodwill and long-lived assets since the results are based on forecasted assumptions. Significant assumptions include:

- *Future liquid hydrocarbon and natural gas prices*. Our estimates of future prices are based on our analysis of market supply and demand and consideration of market price indicators. Although liquid hydrocarbon and natural gas 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 and natural gas prices and estimates of such price curves are inherently imprecise.
- *Estimated recoverable quantities of liquid hydrocarbons, natural gas and bitumen*. This is based on a combination of proved and risk-adjusted probable and possible reserves. 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 risk-adjusted 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 own analysis of various supply and demand factors, which includes, 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. This is based on authorized spending and internal forecasts.

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

The need to test for impairment can be based on several indicators, including a significant reduction in prices of liquid hydrocarbons or natural gas, 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.

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 have two long-term contracts for the sale of natural gas in the United Kingdom that are accounted for as derivative instruments. These contracts, which expire 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 price is reset annually in October and is indexed to a basket of costs of living and energy commodity indices for the previous twelve months. Consequently, the prices under these contracts do not track forward natural gas prices. The fair value of these contracts is 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 result in non-cash charges or credits to income from operations. The difference between the contract price and the U.K. forward natural gas strip price may fluctuate widely from time to time and may significantly affect income from operations. A 10 percent increase in natural gas prices would decrease the fair value of these derivatives by $21 million, while a 10 percent decrease in natural gas prices would increase the fair value of these derivatives by $21 million in 2008.

Our OSM segment holds crude oil options expiring December 2009, which were designed to protect against price decreases on portions of future synthetic crude oil sales. The fair value of these options is measured using a Black-Scholes option pricing model that uses prices from the active commodity market and a market volatility calculated by a third-party service. A 10 percent increase in crude oil prices would decrease the fair value of these options by $4 million, while a 10 percent decrease in crude oil prices would increase the fair value of these options by $13 million in 2008.

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 oil and natural gas 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.

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In determining our overall estimated future taxable income for purposes of assessing the need for additional valuation allowances, we consider proved and risk-adjusted probable reserves related to our existing producing properties, as well as estimated quantities of oil and natural gas 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 13 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, 2008 obligations and estimated 2009 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 6.9 percent for our U.S. pension plans and 6.85 percent for our other U.S. postretirement benefit plans would increase pension obligations and other postretirement benefit plan obligations by $66 million and $21 million and would increase defined benefit pension expense and other postretirement benefit plan expense by $9 million and $3 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 assumptions are compared to those of peer companies and to historical returns for reasonableness and appropriateness. 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.

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Note 23 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 2008, 2007 and 2006, as well as the obligations and accumulated other comprehensive income reported on the balance sheets as of December 31, 2008, and 2007.

In 2006, we made certain plan design changes which included an update of the mortality table used in the plans definition of actuarial equivalence and lump sum calculations and a 20 percent retiree cost of living adjustment for annuitants. This change increased our benefit obligations by $117 million. There were no plan design changes in 2008 or 2007.

Contingent Liabilities

We accrue contingent liabilities for environmental remediation, tax deficiencies unrelated to income 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

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 in their reserve base volumes from unconventional resources. Such unconventional resources include bitumen extracted from oil sands and oil and gas extracted from coal beds and shale formations.

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

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

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

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

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

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

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

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If finalized, we will apply the new disclosure requirements in our annual report on Form 10-K for the year ending December 31, 2009. The new rules may not be applied to disclosures in quarterly reports prior to the first annual report in which the revised disclosures are required. We are currently in the process of evaluating the new requirements.

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

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

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

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

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

In December 2007, the FASB issued SFAS No. 141 (Revised 2007), Business Combinations (SFAS No. 141 (R)). This statement significantly changes the accounting for business combinations. Under SFAS No.141(R), an acquiring entity will be required to recognize all the assets acquired, liabilities assumed and any non-controlling

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interest in the acquiree at their acquisition-date fair value with limited exceptions. The statement expands the definition of a business and is expected to be applicable to more transactions than the previous business combinations standard. The statement also changes the accounting treatment for changes in control, step acquisitions, transaction costs, acquired contingent liabilities, in-process research and development, restructuring costs, changes in deferred tax asset valuation allowances as a result of a business combination and changes in income tax uncertainties after the acquisition date. Accounting for changes in valuation allowances for acquired deferred tax assets and the resolution of uncertain tax positions for prior business combinations will impact tax expense instead of impacting recorded goodwill. Additional disclosures are also required. SFAS No. 141(R) is effective on January 1, 2009, for all new business combinations. The adoption of this standard is not expected to have a significant impact on our consolidated results of operations, financial position or cash flows.

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

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Item 7A. Quantitative and Qualitative Disclosures about Market Risk

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

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

Commodity Price Risk

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

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

Unrealized gains and losses on certain natural gas contracts in the U.K. that are accounted for as derivative instruments are excluded from E&P segment income. These contracts originated in the early 1990s and expire in September 2009. The contract prices are reset annually in October based on the previous twelve-month changes in a basket of energy and other indices. Consequently, the prices under these contracts do not track forward natural gas prices. The reported fair value of the U.K. natural gas contracts is measured with an income approach by applying the difference between the contract price and the U.K. forward natural gas strip price to the expected sales volumes for the shorter of the remaining contract term or 18 months. Such an internally generated model is classified as Level 3 in the fair value hierarchy.

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

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

Generally, commodity derivative instruments used in our E&P segment qualify for hedge accounting. As a result, we do not recognize in net income any changes in the fair value of those derivative instruments until the

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

Open Commodity Derivative Positions as of December 31, 2008 and Sensitivity Analysis

At December 31, 2008, our E&P segment held open derivative contracts to mitigate the price risk on natural gas held in storage or purchased to be marketed with our own natural gas production in amounts that were in line with normal levels of activity. At December 31, 2008, we had no significant open derivative contracts related to our future sales of liquid hydrocarbons and natural gas and therefore remained substantially exposed to market prices of these commodities.

The OSM segment holds crude oil options which were purchased by Western for a three year period (January 2007 to December 2009). The premiums for the purchased put options had been partially offset through the sale of call options for the same three-year period, resulting in a net premium liability. Payment of the net premium liability is deferred until the settlement of the option contracts. As of December 31, 2008, the following put and call options were outstanding:

Option Expiration Date	2009
Option Contract Volumes *(Barrels per day)*:	
Put options purchased	20,000
Call options sold	15,000
Average Exercise Price *(Dollars per barrel)*:	
Put options	$ 50.50
Call options	$ 90.50

In the first quarter of 2009, we sold derivative instruments at an average exercise price of $50.50 which effectively offset the open put options for the remainder of 2009.

At December 31, 2008, the number of open derivative contracts held by our RM&T segment was lower than in previous periods. Starting in the second quarter of 2008, we decreased our use of derivatives to mitigate crude oil price risk between the time that domestic spot crude oil purchases are priced and when they are actually refined into salable petroleum products. Instead, we are addressing this price risk through other means, including changes in contractual terms and crude oil acquisition practices.

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

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Sensitivity analysis of the incremental effects on income from operations (IFO) of hypothetical 10 percent and 25 percent changes in commodity prices for open commodity derivative instruments as of December 31, 2008, is provided in the following table. The direction of the price change used in calculating the sensitivity amount for each commodity reflects that which would result in the largest incremental decrease in IFO when applied to the commodity derivative instruments used to hedge that commodity.

	Incremental Decrease in IFO Assuming a Hypothetical Price Change of[(a)]	
(In millions)	10%	25%
Commodity Derivative Instruments[(b)]		
Crude oil	$ 16(d)	$ 15(d)
Natural gas	21(c)	53(c)
Refined products	6(d)	15(d)

(a) We remain at risk for possible changes in the market value of commodity derivative instruments; however, such risk should be mitigated by price changes in the underlying physical commodity. Effects of these offsets are not reflected in the sensitivity analysis. Amounts reflect hypothetical 10 percent and 25 percent changes in closing commodity prices for each open contract position at December 31, 2008. Included in the natural gas impacts above were $21 million and $53 million for hypothetical price changes of 10 percent and 25 percent related to the U.K. natural gas contracts accounted for as derivative instruments. We evaluate our portfolio of commodity derivative instruments on an ongoing basis and add or revise strategies in anticipation of changes in market conditions and in risk profiles. Changes to the portfolio after December 31, 2008, would cause future IFO effects to differ from those presented above.

(b) The number of net open contracts for the E&P segment varied throughout 2008, from a low of 3 contracts on October 1, 2008, to a high of 472 contracts on January 29, 2008, and averaged 181 for the year. The number of net open contracts for the RM&T segment varied throughout 2008, from a low of 13 contracts on May 16, 2008, to a high of 15,599 contracts on March 17, 2008, and averaged 3,019 for the year. The number of net open contracts for the OSM segment varied throughout 2008, from a low of 12,775 contracts on December 31, 2008, to a high of 24,500 contracts on January 1, 2008, and averaged 18,646 for the year. The commodity derivative instruments used and positions taken will vary and, because of these variations in the composition of the portfolio over time, the number of open contracts by itself cannot be used to predict future income effects.

(c) Price increase.

(d) Price decrease.

Interest Rate Risk

We are impacted by interest rate fluctuations which affect the fair value of certain financial instruments. We manage our exposure to interest rate movements by utilizing financial derivative instruments. The primary objective of this program is to reduce our overall cost of borrowing by managing the mix of fixed and floating interest rate debt in our portfolio. As of December 31, 2008, we had multiple interest rate swap agreements with a total notional amount of $450 million, designated as a fair value hedge, which effectively resulted in an exchange of existing obligations to pay fixed interest rates for obligations to pay floating rates. The weighted average floating rate on these swap agreements is LIBOR plus 2.060 percent.

Sensitivity analysis of the projected incremental effect of a hypothetical 10 percent change in interest rates on financial assets and liabilities as of December 31, 2008, is provided in the following table.

(In millions)	Fair Value	Incremental Change in Fair Value
Financial assets (liabilities)[(a)]		
Receivable from United States Steel	$ 438	$ 11 (c)
Interest rate swap agreements	$ 29 [(b)]	$ 3 (c)
Long-term debt, including amounts due within one year	$ (5,683)[(b)]	$ (358)(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, 2008. For interest rate swap agreements, this assumes a 10 percent decrease in the effective swap rate at December 31, 2008.

At December 31, 2008, our portfolio of long-term debt was substantially comprised of fixed rate instruments. Therefore, the fair value of the portfolio is relatively sensitive to interest rate fluctuations. Our sensitivity to interest rate declines and corresponding increases in the fair value of our debt portfolio unfavorably affects our results of operations and cash flows only when we elect to repurchase or otherwise retire fixed-rate debt at prices above carrying value.

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Foreign Currency Exchange Rate Risk

We manage our exposure to foreign currency exchange rates by utilizing forward and option contracts, although we had no option contracts open at December 31, 2008. 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 table summarizes our derivative foreign currency derivative instruments as of December 31, 2008.

(In millions)	Period		Notional Amount	Average Forward Rate[a]	Fair Value[b]
Foreign Currency Forwards					
Dollar (Canada)	January 2009	February 2010	$ 564	1.063[d]	$ (68)
Euro	January 2009	April 2010	$ 27	1.358[d]	$ 1
Kroner (Norway)	January 2009	November 2009	$ 500	6.263[c]	$ (8)

(a) Rates shown are weighted average forward rates for the period.
(b) Fair value was based on market rates.
(c) U.S. dollar to foreign currency.
(d) Foreign currency to U.S. dollar.

The aggregate cash flow effect on foreign currency contracts of a hypothetical 10 percent change to exchange rates at December 31, 2008, would be $52 million.

Counterparty Risk

We are also exposed to credit 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 crude oil, natural gas, refined products and other feedstocks. If these assumptions prove to be inaccurate, future outcomes with respect to our use of derivative instruments may differ materially from those discussed in the forward-looking statements.

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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, 2008.

The effectiveness of Marathon s internal control over financial reporting as of December 31, 2008 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	*Executive Vice President*

Chief Executive Officer	*and Chief Financial Officer*

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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, 2008, and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, 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, 2008, 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.

As discussed in Note 2 to the consolidated financial statements, the Company changed its method of accounting for purchases and sales of inventory with the same counterparty and defined benefit pension and other postretirement plans in 2006.

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

PricewaterhouseCoopers LLP
Houston, Texas
February 27, 2009

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MARATHON OIL CORPORATION

Consolidated Statements of Income

(In millions, except per share data)	2008	2007	2006
Revenues and other income:			
Sales and other operating revenues (including consumer excise taxes)	$ 75,314	$ 62,800	$ 57,973
Revenue from matching buy/sell transactions		127	5,457
Sales to related parties	1,879	1,625	1,466
Income from equity method investments	765	545	391
Net gain on disposal of assets	423	36	77
Other income	188	74	85
Total revenues and other income	78,569	65,207	65,449
Costs and expenses:			
Cost of revenues (excludes items below)	59,817	49,104	42,415
Purchases related to matching buy/sell transactions		149	5,396
Purchases from related parties	715	363	210
Consumer excise taxes	5,065	5,163	4,979
Depreciation, depletion and amortization	2,178	1,613	1,518
Goodwill impairment	1,412		
Selling, general and administrative expenses	1,387	1,327	1,228
Other taxes	482	394	371
Exploration expenses	490	454	365
Total costs and expenses	71,546	58,567	56,482
Income from operations	7,023	6,640	8,967
Net interest and other financing income (costs)	(50)	41	37
Gain on foreign currency derivative instruments		182	
Loss on early extinguishment of debt		(17)	(35)
Minority interests in loss of Equatorial Guinea LNG Holdings Limited		3	10
Income from continuing operations before income taxes	6,973	6,849	8,979
Provision for income taxes	3,445	2,901	4,022
Income from continuing operations	3,528	3,948	4,957
Discontinued operations		8	277
Net income	$ 3,528	$ 3,956	$ 5,234
Per Share Data			
Basic:			
Income from continuing operations	$ 4.97	$ 5.72	$ 6.92
Discontinued operations	$	$ 0.01	$ 0.39
Net income	$ 4.97	$ 5.73	$ 7.31
Diluted:			
Income from continuing operations	$ 4.95	$ 5.68	$ 6.87

Discontinued operations	$	$ 0.01	$ 0.38
Net income	$ 4.95	$ 5.69	$ 7.25

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

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MARATHON OIL CORPORATION

Consolidated Balance Sheets

	December 31,	
(In millions, except per share data)	2008	2007
Assets		
Current assets:		
Cash and cash equivalents	$ 1,285	$ 1,199
Receivables, less allowance for doubtful accounts of $6 and $3	3,094	5,672
Receivables from United States Steel	23	22
Receivables from related parties	33	79
Inventories	3,507	3,277
Other current assets	461	338
Total current assets	8,403	10,587
Equity method investments	2,080	2,630
Receivables from United States Steel	469	485
Property, plant and equipment, less accumulated depreciation, depletion and amortization of $15,581 and $14,857	29,414	24,675
Goodwill	1,447	2,899
Other noncurrent assets	873	1,470
Total assets	$ 42,686	$ 42,746
Liabilities		
Current liabilities:		
Accounts payable	$ 4,712	$ 7,567
Payables to related parties	21	44
Payroll and benefits payable	400	417
Accrued taxes	1,133	712
Deferred income taxes	561	547
Other current liabilities	828	842
Long-term debt due within one year	98	1,131
Total current liabilities	7,753	11,260
Long-term debt	7,087	6,084
Deferred income taxes	3,330	3,389
Defined benefit postretirement plan obligations	1,609	1,092
Asset retirement obligations	963	1,131
Payable to United States Steel	4	5
Deferred credits and other liabilities	531	562
Total liabilities	21,277	23,523
Commitments and contingencies		
Stockholders Equity		
Preferred stock 5 million shares issued, 3 million and 5 million shares outstanding (no par value, 6 million shares authorized)		
Common stock:		
Issued 767 million and 765 million shares (par value $1 per share, 1.1 billion shares authorized)	767	765
Securities exchangeable into common stock 5 million shares issued, 3 million and 5 million shares outstanding (no par value, unlimited shares authorized)		
Held in treasury, at cost 61 million and 55 million shares	(2,720)	(2,384)

Additional paid-in capital	6,696	6,679
Retained earnings	17,259	14,412
Accumulated other comprehensive loss	(593)	(249)
Total stockholders equity	21,409	19,223
Total liabilities and stockholders equity	$ 42,686	$ 42,746

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

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MARATHON OIL CORPORATION

Consolidated Statements of Cash Flows

(In millions)	2008	2007	2006
Increase (decrease) in cash and cash equivalents			
Operating activities:			
Net income	$ 3,528	$ 3,956	$ 5,234
Adjustments to reconcile net income to net cash provided by operating activities:			
Loss on early extinguishment of debt		17	35
Income from discontinued operations		(8)	(277)
Deferred income taxes	93	(347)	268
Minority interests in loss of Equatorial Guinea LNG Holdings Limited		(3)	(10)
Goodwill impairment	1,412		
Depreciation, depletion and amortization	2,178	1,613	1,518
Pension and other postretirement benefits, net	130	32	(426)
Exploratory dry well costs and unproved property impairments	170	233	166
Net gain on disposal of assets	(423)	(36)	(77)
Equity method investments, net	62	(43)	(200)
Changes in the fair value of U.K. natural gas contracts	(219)	232	(454)
Changes in:			
Current receivables	2,619	(1,338)	(525)
Inventories	(274)	(90)	(133)
Current accounts payable and accrued liabilities	(2,465)	2,312	244
All other, net	(29)	(9)	55
Net cash provided by continuing operations	6,782	6,521	5,418
Net cash provided by discontinued operations			70
Net cash provided by operating activities	6,782	6,521	5,488
Investing activities:			
Capital expenditures	(7,146)	(4,466)	(3,433)
Acquisitions		(3,926)	(741)
Disposal of assets	999	137	134
Disposal of discontinued operations			832
Trusteed funds withdrawals	752	280	
Investments loans and advances	(117)	(114)	(17)
Investments repayments of loans and return of capital	93	59	298
Deconsolidation of Equatorial Guinea LNG Holdings Limited		(37)	
Investing activities of discontinued operations			(45)
All other, net	(16)	(35)	17
Net cash used in investing activities	(5,435)	(8,102)	(2,955)
Financing activities:			
Borrowings	1,247	2,261	
Debt issuance costs	(7)	(20)	
Debt repayments	(1,366)	(694)	(501)
Issuance of common stock	9	27	50
Purchases of common stock	(402)	(822)	(1,698)

Excess tax benefits from stock-based compensation arrangements	7	30	35
Dividends paid	(681)	(637)	(547)
Contributions from minority shareholders of Equatorial Guinea LNG Holdings Limited		39	80
Net cash provided by (used in) financing activities	(1,193)	184	(2,581)
Effect of exchange rate changes on cash	(68)	11	16
Net increase (decrease) in cash and cash equivalents	86	(1,386)	(32)
Cash and cash equivalents at beginning of period	1,199	2,585	2,617
Cash and cash equivalents at end of period	$ 1,285	$ 1,199	$ 2,585

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

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MARATHON OIL CORPORATION

Consolidated Statements of Stockholders Equity

	Stockholders Equity			Shares		
(In millions, except per share data)	2008	2007	2006	2008	2007	2006
Preferred stock issued						
Balance at beginning of year	$	$	$	5		
Issuances					5	
Exchanges				(2)		
Balance at end of year	$	$	$	3	5	
Common stock						
Issued						
Balance at beginning of year	$ 765	$ 736	$ 734	765	736	734
Issuances	2	29	2	2	29	2
Balance at end of year	$ 767	$ 765	$ 736	767	765	736
Securities exchangeable for common stock						
Balance at beginning of year	$	$	$	5		
Issuances					5	
Exchanges				(2)		
Balance at end of year	$	$	$	3	5	
Held in treasury						
Balance at beginning of year	$ (2,384)	$ (1,638)	$ (8)	(55)	(40)	
Repurchases	(412)	(845)	(1,712)	(8)	(17)	(42)
Reissuances for employee stock plans	76	99	82	2	2	2
Balance at end of year	$ (2,720)	$ (2,384)	$ (1,638)	(61)	(55)	(40)
				Comprehensive Income		
				2008	2007	2006
Additional paid-in capital						
Balance at beginning of year	$ 6,679	$ 4,784	$ 4,744			
Stock issuances	(61)	1,844	(8)			
Stock-based compensation	78	51	48			
Balance at end of year	$ 6,696	$ 6,679	$ 4,784			
Unearned compensation						
Balance at beginning of year	$	$	$ (20)			
Change in accounting principle			20			
Balance at end of year	$	$	$			
Retained earnings						
Balance at beginning of year	$ 14,412	$ 11,093	$ 6,406			
Net income	3,528	3,956	5,234	$ 3,528	$ 3,956	$ 5,234
Dividends paid ($0.96 , $0.92 and $0.76 per share)	(681)	(637)	(547)			
Balance at end of year	$ 17,259	$ 14,412	$ 11,093			
Accumulated other comprehensive loss						
Minimum pension liability adjustments						
Balance at beginning of year	$	$	$ (141)			
Changes during year, net of tax of $, $, and $74			114			114
Reclassification to defined benefit postretirement plans			27			

Balance at end of year	$	$	$			
Defined benefit postretirement plans						
Balance at beginning of year	$ (263)	$ (375)	$			
Actuarial gain (loss), net of tax of $146, $87	(248)	110		(248)	110	
Prior service costs, net of tax of $2, $1	2	2		2	2	
Reclassification from minimum pension liability adjustments			(27)			
Change in accounting principle, net of tax of $289			(348)			
Balance at end of year	$ (509)	$ (263)	$ (375)			
Other						
Balance at beginning of year	$ 14	$ 7	$ (10)			
Changes during year, net of tax of $43, $4, and $9	(98)	7	17	(98)	7	12
Balance at end of year	$ (84)	$ 14	$ 7			
Total at end of year	$ (593)	$ (249)	$ (368)			
Comprehensive income				$ 3,184	$ 4,075	$ 5,360
Total stockholders equity	$ 21,409	$ 19,223	$ 14,607			

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

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MARATHON OIL CORPORATION

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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.

Certain reclassifications of prior years data have been made to conform to 2008 classifications.

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.

Matching buy/sell transactions In a typical matching buy/sell transaction, we 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

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counterparty, and simultaneously agrees 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. Prior to April 1, 2006, we recorded all matching buy/sell transactions in both revenues and cost of revenues as separate sale and purchase transactions. Effective April 1, 2006, upon adoption of the provisions of Emerging Issues Task Force (EITF) Issue No. 04-13, we account for matching buy/sell arrangements entered into or modified as exchanges of inventory, except for those arrangements accounted for as derivative instruments.

See Note 2 for further information regarding adoption of EITF Issue No. 04-13.

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.

Derivative instruments We may use derivatives to manage our exposure to commodity price risk, interest rate risk and foreign currency risk. Changes in the fair value of derivatives are recognized immediately in net income unless the derivative qualifies as a hedge of future cash flows or certain foreign currency exposures. 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 hedged 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 hedged transactions.

For derivatives qualifying as hedges of future cash flows or certain foreign currency exposures, the effective portion of any changes in fair value is recognized in other comprehensive income and is reclassified to net income when the underlying forecasted transaction is recognized in net income. Any ineffective portion of such hedges is recognized in net income as it occurs. For discontinued cash flow hedges, prospective changes in the fair value of the derivative are recognized in net income. The accumulated gain or loss recognized in other comprehensive income 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 other comprehensive income is immediately reclassified into net income.

For derivatives designated as hedges of the fair value of recognized assets, liabilities or firm commitments, 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.

In the E&P segment, two natural gas delivery commitment contracts in the United Kingdom are classified as derivative instruments. These contracts contain pricing provisions that are not clearly and closely related to the underlying commodity and therefore must be accounted for as derivative instruments.

As market conditions change, we may use selective derivative instruments that assume market risk. For derivative instruments that are classified as trading, changes in fair value are recognized immediately in net

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income and are classified as other income. Any premium received is amortized into net income based on the underlying settlement terms of the derivative position. All related effects of a trading strategy, including physical settlement of the derivative position, are recognized in net income and classified as other income.

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 that 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. Mobile equipment used in mining operations is depreciated on a straight-line basis over the estimated useful lives of the assets, which range from 10 to 20 years.

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.

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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 refinery maintenance (turnarounds). 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.

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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 fair value calculated and ultimately, the 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. New Accounting Standards

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

SFAS No. 159 In February 2007, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 159, The Fair Value Option for Financial Assets and Financial Liabilities. This statement permits entities to choose to measure at fair value many financial instruments and certain other items that are not currently required to be measured at fair value. It requires that unrealized gains and losses on items for which the fair value option has been elected be recorded in net income. The statement also establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. We did not elect the fair value option when this standard became effective on January 1, 2008, nor have we chosen the fair value option for any assets or liabilities subsequent to that date.

SFAS No. 157 In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 does not require any new fair value measurements but may require some entities to change their measurement practices. Effective January 1, 2008, we adopted SFAS No. 157, except for measurements of those nonfinancial assets and liabilities subject to the one-year deferral, which for us includes impairments of goodwill, intangible assets and other long-lived assets, and initial measurement of asset retirement obligations, asset exchanges, business combinations and partial sales of proved properties. Adoption did not have a significant effect on our consolidated results of operations or financial position.

In February 2008, the FASB issued FSP FAS 157-1, Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of

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Lease Classification or Measurement under Statement 13, which removes certain leasing transactions from the scope of SFAS No. 157, and FSP FAS 157-2, Effective Date of FASB Statement No. 157, which defers the effective date of SFAS No. 157 for one year for certain nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis.

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

The additional disclosures regarding assets and liabilities recorded at fair value and measured under SFAS No. 157 are presented in Note 17.

SFAS No. 158 In September 2006, the FASB issued SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans An Amendment of FASB Statements No. 87, 88, 106, and 132 (R). This standard requires an employer to: (1) recognize in its statement of financial position an asset for a plan s overfunded status or a liability for a plan s underfunded status; (2) measure a plan s assets and its obligations that determine its funded status as of the end of the employer s fiscal year (with limited exceptions); and (3) recognize changes in the funded status of a plan in the year in which the changes occur through comprehensive income. The funded status of a plan is measured as the difference between plan assets at fair value and the benefit obligation. For a pension plan, the benefit obligation is the projected benefit obligation and for any other postretirement plan it is the accumulated postretirement benefit obligation. We adopted SFAS No. 158 prospectively as of December 31, 2006 and recognized the funded status of our plans in the consolidated balance sheets, with a cumulative effect of a change in accounting principle of $348 million in stockholders equity. The adoption of SFAS No. 158 had no impact on our measurement date as we have historically measured the plan assets and benefit obligations of our pension and other postretirement plans as of December 31. See Note 23 for additional disclosures regarding defined benefit pension and other postretirement plans required by SFAS No. 158.

EITF Issue No. 04-13 In September 2005, the FASB ratified the consensus reached by the EITF on Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty. The consensus establishes the circumstances under which two or more inventory purchase and sale transactions with the same counterparty should be recognized at fair value or viewed as a single exchange transaction subject to APB Opinion No. 29, Accounting for Nonmonetary Transactions. In general, two or more transactions with the same counterparty must be combined for purposes of applying APB Opinion No. 29 if they are entered into in contemplation of each other. The purchase and sale transactions may be pursuant to a single contractual arrangement or separate contractual arrangements and the inventory purchased or sold may be in the form of raw materials, work-in-process or finished goods.

Effective April 1, 2006, we adopted the provisions of EITF Issue No. 04-13 prospectively. EITF Issue No. 04-13 changes the accounting for matching buy/sell arrangements that are entered into or modified on or after April 1, 2006 (except for those accounted for as derivative instruments). In a typical matching buy/sell transaction, we 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 agrees 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. Prior to adoption of EITF Issue No. 04-13, we recorded such matching buy/sell transactions in both revenues and cost of revenues as separate sale and purchase transactions. Upon adoption, we accounted for such transactions as exchanges of inventory.

Transactions arising from matching buy/sell arrangements entered into before April 1, 2006 were reported as separate sale and purchase transactions, until all such contracts ceased.

The adoption of EITF Issue No. 04-13 no effect on net income. The amounts of revenues and cost of revenues recognized after April 1, 2006 are less than the amounts that would have been recognized under previous accounting practices.

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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.

Tax Sharing Agreement Marathon and United States Steel entered into a Tax Sharing Agreement that reflects each party s rights and obligations relating to payments and refunds of income, sales, transfer and other taxes that are attributable to periods beginning prior to and including the USX Separation date and taxes resulting from transactions effected in connection with the USX Separation.

In 2006, in accordance with the terms of the Tax Sharing Agreement, Marathon paid $35 million to United States Steel in connection with the settlement with the Internal Revenue Service of the consolidated federal income tax returns of USX Corporation for the years 1995 through 2001. The final payment of $13 million to United States Steel related to income tax returns under the Tax Sharing Agreement was made in January 2007.

4. Deconsolidation of Equatorial Guinea LNG Holdings Limited

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,

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EGHoldings was no longer a VIE. Effective May 1, 2007, we no longer consolidate 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. Our investment is included in the equity method investments line of our consolidated balance sheet (see Note 14 to the consolidated financial statements).

5. Related Party Transactions

During 2008, 2007 and 2006 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.

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.

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.

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 in the United States.

Poseidon Oil Pipeline Company, L.L.C. (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.

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Related party sales to PTC consist primarily of petroleum products. Revenues from related parties were as follows:

(In millions)	2008	2007	2006
PTC	$ 1,789	$ 1,556	$ 1,420
EGHoldings	39	19	
Centennial	31	27	28
Other equity method investees	20	23	18
Total	$ 1,879	$ 1,625	$ 1,466

Purchases from related parties were as follows:

(In millions)	2008	2007	2006
Alba Plant LLC	$ 235	$ 131	$
Ethanol investments	188	9	
Poseidon	154	16	8
Centennial	61	57	53
LOOP LLC	35	43	54
Other equity method investees	42	107	95
Total	$ 715	$ 363	$ 210

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).

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The primary reasons for the acquisition and the principal factors contributing to a purchase price resulting in goodwill are: access to the long-life Athabasca Oil Sands Project (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 table summarizes the fair values of the assets and liabilities acquired as of October 18, 2007.

(In millions)	
Current assets:	
Cash and cash equivalents	$ 44
Receivables	359
Inventories	26
Other current assets	40
Total current assets acquired	469
Property, plant and equipment	6,842
Goodwill	1,483
Intangible assets	113
Other noncurrent assets	10
Total assets acquired	$ 8,917
Current liabilities:	
Accounts payable	$ 339
Current portion of long-term debt	50
Deferred income taxes	48
Other current liabilities	20
Total current liabilities assumed	457
Long-term debt	1,013
Deferred income taxes	1,494
Asset retirement obligations	31
Other liabilities	89
Total liabilities assumed	3,084
Net assets acquired	$ 5,833

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	2006
Revenues and other income	$ 66,089	$ 66,283
Income from continuing operations	3,495	4,765
Net income	3,503	5,042
Per share data:		
Income from continuing operations basic	$ 5.07	$ 6.35
Income from continuing operations diluted	$ 5.03	$ 6.30
Net income basic	$ 5.08	$ 6.72
Net income diluted	$ 5.04	$ 6.67

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7. Dispositions

Outside-operated Norwegian properties On October 31, 2008, we closed the sale of our Norwegian outside-operated 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 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.

Operated Irish properties On December 17, 2008, we agreed to sell our operated properties located in Ireland for proceeds of $180 million, before post-closing adjustments and cash on hand at closing. Closing is subject to completion of the necessary administrative processes.

As of December 31, 2008, operating assets and liabilities were classified as held for sale, as disclosed by major class in the following table:

(In millions)	2008
Current assets	$ 164
Noncurrent assets	103
Total assets	267
Current liabilities	62
Noncurrent liabilities	199
Total liabilities	261
Net assets held for sale	$ 6

8. Discontinued Operations

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. A gain on the sale of $243 million ($342 million before income taxes) was reported in discontinued operations for 2006. Income taxes on this gain were reduced by the utilization of a capital loss carryforward. Exploration and Production segment goodwill of $21 million was allocated to the Russian assets and reduced the reported gain. Adjustments to the sales price were completed in 2007 and an additional gain on the sale of $8 million ($13 million before income taxes) was recognized.

The activities of the Russian businesses have been reported as discontinued operations in the consolidated statements of income and the consolidated statements of cash flows for 2006. Revenues applicable to discontinued operations were $173 million and pretax income from discontinued operations was $45 million for 2006.

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9. 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, stock appreciation rights and restricted stock, provided the effect is not antidilutive.

	2008		2007		2006	
(In millions except per share data)	Basic	Diluted	Basic	Diluted	Basic	Diluted
Income from continuing operations	$ 3,528	$ 3,528	$ 3,948	$ 3,948	$ 4,957	$ 4,957
Discontinued operations			8	8	277	277
Net income	$ 3,528	$ 3,528	$ 3,956	$ 3,956	$ 5,234	$ 5,234
Weighted average common shares outstanding	709	709	690	690	716	716
Effect of dilutive securities		4		5		6
Weighted average common shares, including dilutive effect	709	713	690	695	716	722
Per share:						
Income from continuing operations	$ 4.97	$ 4.95	$ 5.72	$ 5.68	$ 6.92	$ 6.87
Discontinued operations	$	$	$ 0.01	$ 0.01	$ 0.39	$ 0.38
Net income	$ 4.97	$ 4.95	$ 5.73	$ 5.69	$ 7.31	$ 7.25

The per share calculations above exclude 5.4 million and 3.2 million stock options and stock appreciation rights in 2008 and 2007 that were antidilutive. There were no antidilutive stock options or stock appreciation rights in 2006. Restricted stock was not antidilutive in 2008, 2007 or 2006.

10. Segment Information

We have four reportable operating segments: Exploration and Production; Oil Sands Mining; Refining, Marketing and Transportation; and Integrated Gas. 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 by-products;

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.; and

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.

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 minority interests and 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. All 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 are accounted for as derivative instruments, impairments or infrequently occurring items (as determined by the CODM) also are not allocated to operating segments.

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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	OSM	RM&T	IG	Total
2008					
Revenues:					
Customer	$ 11,636	$ 922	$ 62,445	$ 93	$ 75,096
Intersegment[a]	798	200	209		1,207
Related parties	52		1,827		1,879
Segment revenues	12,486	1,122	64,481	93	78,182
Elimination of intersegment revenues	(798)	(200)	(209)		(1,207)
Gain on U.K. natural gas contracts	218				218
Total revenues	$ 11,906	$ 922	$ 64,272	$ 93	$ 77,193
Segment income	$ 2,715	$ 258	$ 1,179	$ 302	$ 4,454
Income from equity method investments[b]	225		178	402	805
Depreciation, depletion and amortization[b]	1,386	143	606	3	2,138
Income tax provision[b]	2,912	93	684	131	3,820
Capital expenditures[c][d]	3,113	1,038	2,954	4	7,109
2007					
Revenues:					
Customer	$ 8,623	$ 181	$ 54,137	$ 218	$ 63,159
Intersegment[a]	497	40	348		885
Related parties	35		1,590		1,625
Segment revenues	9,155	221	56,075	218	65,669
Elimination of intersegment revenues	(497)	(40)	(348)		(885)
Loss on U.K. natural gas contracts	(232)				(232)
Total revenues	$ 8,426	$ 181	$ 55,727	$ 218	$ 64,552
Segment income (loss)	$ 1,729	$ (63)	$ 2,077	$ 132	$ 3,875
Income from equity method investments	238		139	168	545
Depreciation, depletion and amortization[b]	963	22	587	6	1,578
Minority interest in loss of subsidiary				3	3
Income tax provision (benefit)[b]	2,172	(21)	1,183	24	3,358
Capital expenditures[c][d]	2,511	165	1,640	93	4,409
2006					
Revenues:					
Customer	$ 8,326	$	$ 54,471	$ 179	$ 62,976
Intersegment[a]	672		16		688
Related parties	12		1,454		1,466
Segment revenues	9,010		55,941	179	65,130
Elimination of intersegment revenues	(672)		(16)		(688)
Gain on U.K. natural gas contracts	454				454

Total revenues	$ 8,792	$	$ 55,925	$ 179	$ 64,896
Segment income	$ 2,003	$	$ 2,795	$ 16	$ 4,814
Income from equity method investments	206		145	40	391
Depreciation, depletion and amortization[(b)]	919		558	9	1,486
Minority interest in loss of subsidiary				10	10
Income tax provision[(b)]	2,371		1,642	8	4,021
Capital expenditures[(c)(d)]	2,169		916	307	3,392

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

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

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

(d) Through April 2007, Integrated Gas segment capital expenditures include 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.

(e) As discussed in Note 8, the Russian businesses that were sold on June 2, 2006 have been accounted for as discontinued operations. Segment information for all presented periods excludes the amounts for these Russian operations.

(f) As discussed in Note 6, we acquired Western in October 18, 2007.

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

(In millions)	2008	2007	2006
Segment income	$ 4,454	$ 3,875	$ 4,814
Items not allocated to segments, net of income taxes:			
Corporate and other unallocated items	(93)	(122)	(190)
Gain (loss) on U.K. natural gas contracts	111	(118)	232
Foreign currency gain (loss) on income taxes	252	18	(22)
Impairments[a]	(1,437)		
Gain on dispositions	241	8	274
Gain on foreign currency derivative instruments		112	
Deferred income taxes tax legislation changes		193	21
other adjustments[b]			93
Loss on early extinguishment of debt		(10)	(22)
Discontinued operations			34
Net income	$ 3,528	$ 3,956	$ 5,234

[a] Impairments include the $1,412 million impairment of goodwill related to the OSM reporting unit, see Note 16 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 14 to the consolidated financial statements.

[b] Other deferred tax adjustments in 2006 represent a benefit recorded for cumulative income tax basis differences associated with prior periods.

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)	2008	2007	2006
Total revenues	$ 77,193	$ 64,552	$ 64,896
Less: Sales to related parties	1,879	1,625	1,466
Revenues from matching buy/sell transactions		127	5,457
Sales and other operating revenues (including consumer excise taxes)	$ 75,314	$ 62,800	$ 57,973

The following summarizes revenues from external customers by geographic area.

(In millions)	2008	2007	2006
United States	$ 69,034	$ 59,302	$ 59,723
International	8,159	5,250	5,173
Total	$ 77,193	$ 64,552	$ 64,896

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

(In millions)	December 31, 2008	2007
United States	$ 16,298	$ 13,133
Canada	7,775	6,980
Equatorial Guinea	2,732	2,842
Other international	4,719	4,393
Total	$ 31,524	$ 27,348

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Revenues by product line were:

(In millions)	2008	2007	2006
Refined products	$ 59,299	$ 49,718	$ 45,511
Merchandise	3,028	2,975	2,871
Liquid hydrocarbons	11,422	8,919	12,531
Natural gas	3,085	2,629	3,742
Transportation and other	359	311	241
Total	$ 77,193	$ 64,552	$ 64,896

11. Other Items

Net interest and other financing income (costs)

(In millions)	2008	2007	2006
Interest and other financial income:			
Interest income	$ 60	$ 144	$ 129
Net foreign currency gains	14	2	16
Total	74	146	145
Interest and other financing costs:			
Interest incurred[(a)]	440	290	245
Loss (income) on interest rate swaps	(1)	15	16
Interest capitalized	(326)	(214)	(152)
Net interest expense	113	91	109
Other	11	14	(1)
Total	124	105	108
Net interest and other financial income (costs)	$ (50)	$ 41	$ 37

(a) Excludes $29 million, $30 million and $33 million paid by United States Steel in 2008, 2007 and 2006 on assumed debt.

Foreign currency transactions Aggregate foreign currency gains (losses) were included in the consolidated statements of income as follows:

(In millions)	2008	2007	2006
Net interest and other financing costs	$ 14	$ 2	$ 16
Provision for income taxes	252	18	(22)
Aggregate foreign currency gains (losses)	$ 266	$ 20	$ (6)

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12. Income Taxes

Income tax provisions (benefits) were:

	2008			2007			2006		
(In millions)	Current	Deferred	Total	Current	Deferred	Total	Current	Deferred	Total
Federal	$ 923	$ 193	$ 1,116	$ 1,290	$ (2)	$ 1,288	$ 1,579	$ 72	$ 1,651
State and local	146	12	158	184	22	206	230	30	260
Foreign	2,283	(112)	2,171	1,774	(367)	1,407	1,945	166	2,111
Total	$ 3,352	$ 93	$ 3,445	$ 3,248	$ (347)	$ 2,901	$ 3,754	$ 268	$ 4,022

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:

(In millions)	2008	2007	2006
Statutory rate applied to income from continuing operations before income taxes	$ 2,440	$ 2,397	$ 3,143
Effects of foreign operations, including foreign tax credits[(a)]	1,168	671	909
Effects of nondeductible goodwill impairment	494		
Adjustments to valuation allowances[(b)]	(671)		
State and local income taxes, net of federal income tax effects	92	134	170
Credits other than foreign tax credits	(7)	(3)	(2)
Domestic manufacturing deduction	(44)	(64)	(47)
Effects of partially-owned companies	(4)	(5)	(6)
Effects of enacted changes in tax laws[(c)]		(193)	(21)
Adjustment of prior years federal income taxes[(d)]	(30)	(27)	(119)
Other	7	(9)	(5)
Provision for income taxes	$ 3,445	$ 2,901	$ 4,022

(a) In 2006, we resumed operations in Libya where the statutory income tax rate is in excess of 90 percent.

(b) The adjustments to the valuation allowance related primarily to the release of the Norwegian valuation allowance. In 2008, we released the valuation allowance on the Norwegian deferred tax asset upon completion of the operated Alvheim/Vilje development offshore Norway, with first production from Alvheim in June 2008 and from Vilje in July 2008.

(c) The amounts in all periods represent the income tax benefits of applying income tax rate changes to the applicable net deferred tax asset or liability balances. In 2007, subsequent to the Western acquisition, decreases to the Canadian income tax rates were enacted. In 2006, the U.K. supplemental corporation tax rate (SCT) was increased, which resulted in a benefit due to the net deferred tax asset position related to the SCT.

(d) The 2006 adjustment of prior years federal income taxes was primarily related to a $93 million credit as a result of an analysis of the tax consequences attributable to prior years differences between the financial statement carrying amounts of assets and liabilities and their tax bases for U.S. federal income tax purposes.

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Deferred tax assets and liabilities resulted from the following:

(In millions)	December 31, 2008	2007
Deferred tax assets:		
Employee benefits	$ 918	$ 703
Operating loss carryforwards[(a)]	1,150	1,596
Derivative instruments	86	284
Foreign tax credits[(b)]	1,088	838
Other	160	169
Valuation allowances		
Federal[(c)]		(29)
State	(50)	(55)
Foreign[(d)]	(212)	(917)
Total deferred tax assets	3,140	2,589
Deferred tax liabilities:		
Property, plant and equipment	4,679	4,610
Inventories	649	652
Investments in subsidiaries and affiliates	1,361	987
Other	63	89
Total deferred tax liabilities	6,752	6,338
Net deferred tax liabilities	$ 3,612	$ 3,749

(a) At December 31, 2008, foreign operating loss carryforwards primarily include $562 million for Norway regular income tax, $1,044 million for Norway special petroleum tax and $585 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 2009 through 2020. State operating loss carryforwards of $719 million expire in 2009 through 2028. The state operating loss carryforwards primarily relate to the period prior to the USX Separation and were 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), income generated from foreign sources and our tax profile in the years that such credits may be claimed.

(c) Federal valuation allowances decreased $29 million in 2008 and increased $10 million in 2007 primarily due to the realizibility of foreign tax credits. In 2006, federal valuation allowances decreased $101 million primarily due to $79 million of carryforward losses utilized in conjunction with the sale of our Russian oil exploration and production businesses.

(d) Foreign valuation allowances decreased $705 million in 2008, primarily due to the release of the Norwegian valuation allowance. Foreign valuation allowances increased $306 million and $176 million in 2007 and 2006 primarily as a result of net operating loss carryforwards generated in those years in Norway, Angola and several other jurisdictions.

Net deferred tax liabilities were classified in the consolidated balance sheet as follows:

(In millions)	December 31, 2008	2007

Assets:		
Other current assets	$ 36	$ 2
Other noncurrent assets	243	185
Liabilities:		
Current deferred income taxes	561	547
Noncurrent deferred income taxes	3,330	3,389
Net deferred tax liabilities	$ 3,612	$ 3,749

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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 or provided for these liabilities. As of December 31, 2008, our income tax returns remain subject to examination in the following major tax jurisdictions for the tax years indicated.

United States[a]	2001	2007
Canada	2000	2007
Equatorial Guinea	2006	2007
Libya	2006	2007
Norway	2007	
United Kingdom	2007	

(a) Includes federal and state jurisdictions.

We adopted FIN No 48 as of January 1, 2007. Total unrecognized tax benefits were $39 million and $40 million as of December 31, 2008 and 2007. If the unrecognized tax benefits as of December 31, 2008 were recognized, $29 million would affect our effective income tax rate. There were $10 million of uncertain tax positions as of that date for which it is reasonably possible that the amount of unrecognized tax benefits would significantly decrease during 2009.

The following table summarizes the activity in unrecognized tax benefits:

(In millions)	2008	2007
January 1 balance	$ 40	$ 48
Additions based on tax positions related to the current year		11
Additions for tax positions of prior years	24	30
Reductions for tax positions of prior years	(26)	(30)
Settlements	1	(19)
December 31 balance	$ 39	$ 40

In connection with the adoption of FIN No. 48, 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 a net $14 million credit to income in the year ended December 31, 2008 and were a net $8 million credit to income for the year ended December 31, 2007. As of December 31, 2008 and 2007, $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 $4,962 million in 2008, $2,900 million in 2007, and $3,570 million in 2006.

Undistributed income of certain consolidated foreign subsidiaries at December 31, 2008 amounted to $1,626 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 $569 million would have been incurred.

13. Inventories

	December 31,	
(In millions)	2008	2007
Liquid hydrocarbons, natural gas and bitumen	$ 1,376	$ 1,203
Refined products and merchandise	1,797	1,792
Supplies and sundry items	334	282
Total, at cost	$ 3,507	$ 3,277

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The LIFO method accounted for 90 percent and 89 percent of total inventory value at December 31, 2008 and 2007. Current acquisition costs were estimated to exceed the LIFO inventory value at December 31, 2008 and 2007 by $777 million and $4,034 million.

14. Equity Method Investments

	Ownership as of December 31, 2008	December 31,	
(In millions)		2008	2007
EGHoldings[a]	60%	$ 1,053	$ 1,014
Alba Plant LLC	52%	315	395
Atlantic Methanol Production Company LLC[b]	45%	235	245
LOOP LLC	51%	143	183
Ethanol investments[c]	35% / 50%	70	97
PTC[d]	0%		493
Other		264	203
Total		$ 2,080	$ 2,630

[a] As discussed in Note 4, we ceased consolidating EGHoldings effective May 1, 2007; thereafter, our investments has been accounted for using the equity method of accounting. EGHoldings results are included in the income data below after May 1, 2007.

[b] Atlantic Methanol Production Company LLC is engaged in methanol production activity.

[c] As discussed in Note 5, Ethanol investments represent our ownership in The Andersons Clymers Ethanol LLC and The Anderson Marathon Ethanol LLC.

[d] On October 8, 2008, we completed the sale of our 50 percent ownership interest in Pilot Travel Centers LLC, as discussed in Note 7 to the consolidated financial statements.

Our Ethanol investments were impaired by $40 million ($25 million, net of tax), in the fourth quarter of 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)	2008	2007	2006
Income data year:			
Revenues and other income	$ 15,766	$ 14,133	$ 11,873
Income from operations	1,608	1,098	746
Net income	1,436	1,038	710
Balance sheet data December 31:			
Current assets	$ 837	$ 1,279	
Noncurrent assets	4,692	5,998	
Current liabilities	993	1,512	
Noncurrent liabilities	821	1,378	

As of December 31, 2008, the carrying value of our equity method investments was $361 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 $827 million in 2008, $502 million in 2007 and $191 million in 2006. 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.

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15. Property, Plant and Equipment

(In millions, except per share data)	December 31, 2008	2007
Exploration and production	$ 22,497	$ 21,232
Oil sands mining and bitumen upgrading	7,935	6,691
Refining	9,026	6,462
Marketing	2,144	2,123
Transportation	2,592	2,331
Gas Liquefaction	26	26
Other	775	667
Total	$ 44,995	$ 39,532
Less accumulated depreciation, depletion and amortization	15,581	14,857
Net property, plant and equipment	$ 29,414	$ 24,675

Property, plant and equipment includes gross assets acquired under capital leases of $82 million and $74 million at December 31, 2008 and 2007, with related amounts in accumulated depreciation, depletion and amortization of $18 million and $13 million at December 31, 2008 and 2007.

Property impairments were $21 million, $19 million and $25 million in 2008, 2007 and 2006. The economic and commodity price declines in the latter part of 2008 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, except per share data)	December 31, 2008	2007	2006
Amounts capitalized less than one year after completion of drilling	$ 863	$ 683	$ 377
Amounts capitalized greater than one year after completion of drilling	54	100	93
Total deferred exploratory well costs	$ 917	$ 783	$ 470
Number of projects with costs capitalized greater than one year after completion of drilling	2	3	3

Exploratory well costs capitalized greater than one year after completion of drilling as of December 31, 2008 included $30 million related to wells in Equatorial Guinea (primarily Corona and Gardenia) that was primarily incurred in 2004 and $24 million for the Gudrun appraisal well offshore Norway that was primarily incurred in 2006.

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.

Development plans are underway for the North Sea Gudrun field, which contains both oil and natural gas. The development concept was announced by the operator in January 2009. We hold a 28 percent working interest in Gudrun. A final investment decision is expected in 2009.

The net changes in deferred exploratory well costs were as follows:

(In millions)	2008	2007	2006
Beginning Balance	$ 783	$ 470	$ 363
Additions	413	394	174
Dry well expense	(63)	(39)	(27)
Transfers to development	(216)	(42)	(21)
Dispositions			(19)
Ending Balance	$ 917	$ 783	$ 470

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16. 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 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.

The disruption in the credit and equity markets and the significant change in commodity prices that transpired during the latter part of 2008 impacts several of the significant assumptions used in our determination of fair value. As a result, we tested goodwill for impairment again in the fourth quarter of 2008 for our E&P and OSM reporting units.

As there was limited market-based data 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 considers 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 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 is 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 continue to deteriorate or commodity prices continue to decline, the goodwill of our other reporting units could require impairment.

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The changes in the carrying amount of goodwill for the years ended December 31, 2007, and 2008, were as follows:

(In millions)	E&P	OSM	RM&T	Total
Balance as of December 31, 2006	$ 519	$	$ 879	$ 1,398
Acquired	71	1,437		1,508
Adjusted[(a)]			(7)	(7)
Balance as of December 31, 2007	590	1,437	872	2,899
Adjusted[(a)]	(17)	(25)	7	(35)
Impaired		(1,412)		(1,412)
Disposed[(b)]	(5)			(5)
Balance as of December 31, 2008	$ 568	$	$ 879	$ 1,447

(a) Adjustments related to prior period income tax and royalty adjustments.

(b) Goodwill was allocated to the Norwegian outside-operated properties sold in 2008.

17. Fair Value Measurements

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

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

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

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

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

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

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The following table presents net financial assets and liabilities accounted for at fair value on a recurring basis as of 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 $121 million in broker accounts covered by master netting agreements are included in fair values of commodity derivatives. Derivatives in Level 1 are exchange-traded contracts for crude oil, natural gas, refined products and ethanol measured at fair value with a market approach using the close-of-day settlement prices for the market. Derivatives in Level 2 are measured at fair value with a market approach using broker quotes or third-party pricing services, which have been corroborated with data from active markets. Level 3 derivatives are measured at fair value using either a market or income approach. Generally at least one input is unobservable, such as the use of an internally generated model or an external data source.

Commodity derivatives in Level 3 include a $72 million liability related to two U.K. natural gas sales contracts that are 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 is measured with an income approach by applying the difference between the contract price and the U.K. forward natural gas strip price to the expected sales volumes for the shorter of the remaining contract term or 18 months. These contracts originated in the early 1990s and expire in September 2009. The contract prices are reset annually in October based on the previous twelve-month changes in a basket of energy and other indices. Consequently, the prices under these contracts do not track forward natural gas prices. The crude oil options, which expire December 2009, are measured at fair value using a Black-Scholes option pricing model, an income approach that utilizes prices from an active market and market volatility calculated by a third-party service.

The interest rate derivatives are measured at fair value using quotes from our counterparties which are compared to internal calculations made using rates posted by a pricing service. Because we are unable to independently verify those rates directly to the market, such inputs are considered Level 3.

The following is a reconciliation of the net beginning and ending balances recorded for derivative instruments classified as Level 3 in the fair value hierarchy.

(In millions)	December 31, 2008
Beginning balance	$(355)
Total realized and unrealized losses:	
Included in net income	210
Included in other comprehensive income	1
Purchases, sales, issuances and settlements, net	118

Ending balance	$ (26)

The change in unrealized losses included in net income related to instruments held at December 31, 2008, was an addition of $299 million for 2008. Amounts reported in net income are classified as sales and other operating revenues or cost of revenues for commodity derivative instruments, as net interest and other financing income for interest rate derivative instruments and as cost of revenues for foreign currency derivatives, except those designated as hedges of future capital expenditures. Amounts related to foreign currency derivatives designated as hedges of future capital expenditures accumulate in other comprehensive income and are amortized to depletion, depreciation and amortization over the life of the capital asset.

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The following table summarizes financial instruments, excluding the derivative financial instruments reported above, by individual balance sheet line item at December 31, 2008 and 2007.

	December 31,			
	2008		2007	
(In millions)	Fair Value	Carrying Amount	Fair Value	Carrying Amount
Financial assets				
Receivables from United States Steel, including current portion	$ 438	$ 492	$ 500	$ 507
Other noncurrent assets[(a)]	286	113	1,140	899
Total financial assets	724	605	1,640	1,406
Financial liabilities				
Long-term debt, including current portion[(b)]	5,683	6,880	7,176	6,947
Total financial liabilities	$ 5,683	$ 6,880	$ 7,176	$ 6,947

(a) Includes restricted cash, cost method investments and miscellaneous long-term receivables or deposits.

(b) Excludes capital leases.

Our current assets and liabilities accounts contain financial instruments, the most significant of which are trade accounts receivables and payables. We believe the carrying values of our current assets and liabilities approximate fair value, with the exception of the current portion of receivables from United States Steel and the current portion of our long-term debt which is reported above. Our fair value assessment incorporates a variety of considerations, including (1) the short-term duration of the instruments (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.

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.

Long-term receivables and deposits are also measured using an income approach. The expected timing of payments are scheduled and then discounted using a rate deemed appropriate.

18. Derivative Instruments

Derivative instruments are recorded at fair value. Derivative instruments on our consolidated balance sheet are reported on a net basis by brokerage firm, as permitted by master netting agreements. For further information regarding the fair value measurement of derivative instruments see Note 17.

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The following table sets forth quantitative information by category of derivative instrument at December 31, 2008 and 2007. These amounts are reported on a gross basis by individual derivative instrument.

	2008		2007	
(In millions)	Assets	(Liabilities)	Assets	(Liabilities)
Commodity Instruments				
Fair value hedges:[a]				
OTC commodity swaps	$	$ (12)	$ 10	$ (5)
Non-hedge designation:				
Exchange-traded commodity futures	279	(277)	423	(506)
Exchange-traded commodity options	16	(18)	312	(287)
OTC commodity swaps	25	(55)	17	(26)
OTC commodity options	65	(14)		(136)
U.K. natural gas contracts[b]		(72)		(291)
Physical commodity contracts[c]			271	(198)
Financial Instruments				
Fair value hedges:				
OTC interest rate swaps[d]	29			(3)
Cash flow hedges:[e]				
OTC foreign currency forwards	$ 2	$ (77)	$ 12	$

(a) There was no ineffectiveness associated with fair value hedges for 2008 or 2007 because the hedging instruments and the existing firm commitment contracts were priced on the same underlying index. Derivative instruments used in the fair value hedges mature in 2009.

(b) The contract price under the U.K. natural gas contracts is reset annually and is indexed to a basket of costs of living and energy commodity indices for the previous 12 months. The fair value of these contracts is 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 expire September, 2009.

(c) Certain physical commodity contracts were classified as derivative instruments in 2007 because certain volumes covered by these contracts were physically netted at particular delivery locations. The netting process caused all contracts at such delivery locations to be considered derivative instruments. Other physical contracts that we chose not to designate as normal purchases or normal sales in that period were also been accounted for as derivative instruments. Beginning in the second quarter of 2008, we ceased netting volumes and elected the normal purchase and normal sale designation for our physical commodity contracts; therefore reducing substantially our number of derivative instruments.

(d) The fair value of OTC interest rate swaps excludes accrued interest amounts not yet settled. As of December 31, 2008, and 2007, accrued interest was a receivable of $1 million and a payable of $3 million. The net fair value of the OTC interest rate swaps as of December 31, 2008 and 2007 is included in long-term debt. See Note 20.

(e) The changes in fair value of cash flow hedges included less than $1 million ineffectiveness during 2008 and no ineffectiveness during 2007.

19. Short Term Debt

We have a commercial paper program that is supported by the unused and available credit on our revolving credit facility discussed in Note 20. At December 31, 2008 and 2007, there were no commercial paper borrowings outstanding.

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20. Long Term Debt

Our long term debt agreements do not contain restrictive financial covenants.

	December 31,	
(In millions)	2008	2007
Marathon Oil Corporation:		
Revolving credit facility[a]	$	$
6.850% notes due 2008		400
6.125% notes due 2012[b]	450	450
6.000% notes due 2012[b]		