MARATHON OIL CORP
Form 10-K
February 29, 2008
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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, 2007

Commission file number 1-5153

Marathon Oil Corporation

(Exact name of registrant as specified in its charter)

Delaware	**25-0996816**
(State of Incorporation)	**(I.R.S. Employer Identification No.)**

5555 San Felipe Road, Houston, TX 77056-2723

(Address of principal executive offices)

Tel. No. (713) 629-6600

Securities registered pursuant to Section 12 (b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $1.00	New York Stock Exchange and Chicago Stock Exchange

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. ¨

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, 2007: $40.740 billion. 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 708,970,468 shares of Marathon Oil Corporation Common Stock outstanding as of January 31, 2008.

Documents Incorporated By Reference:

Portions of the registrant s proxy statement relating to its 2008 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 t 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 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 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.

Acquisition of 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 billion. Western s debt was $1.063 billion at closing. 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

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purchase method of accounting and, as such, our results of operations include Western s results from October 18, 2007. Western s oil sands mining and bitumen upgrading operations are reported as a separate Oil Sands Mining segment, while its ownership interests in leases where in-situ recovery techniques are expected to be utilized are included in the Exploration and Production segment.

Segment and Geographic Information

Our operations consist of four 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 9 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 11 countries. Principal exploration activities are in the United States, Angola, Norway and Indonesia. Principal development and production activities are in the United States, the United Kingdom, Norway, Ireland, Equatorial Guinea and Libya.

Our 2007 worldwide net liquid hydrocarbon sales averaged 197 thousand barrels per day (mbpd). Our 2007 worldwide net natural gas sales, including natural gas acquired for injection and subsequent resale, averaged 925 million cubic feet per day (mmcfd). In total, our 2007 worldwide net sales averaged 351 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.) In 2008, our worldwide net liquid hydrocarbon and natural gas sales are expected to average 380 to 420 mboepd, excluding future acquisitions and dispositions.

The above projections of 2008 worldwide net liquid hydrocarbon and natural gas sales are forward-looking statements. Some factors that could potentially affect levels of sales include pricing, supply and demand for petroleum products, the amount of capital available for exploration and development, regulatory constraints, timing of commencing production from new wells, drilling rig availability, inability to obtain or delay in obtaining necessary government and third-party approvals and permits, unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response, and other geological, operating and economic considerations. These factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Exploration

In the United States during 2007, we drilled 59 gross (39 net) exploratory wells of which 47 gross (29 net) wells encountered commercial quantities of hydrocarbons. Of these 47 wells, none were temporarily suspended or in the process of being completed at year end. Internationally, we drilled 25 gross (6 net) exploratory wells of which 16 gross (4 net) wells encountered commercial quantities of hydrocarbons. Of these 16 wells, 10 gross (3 net) wells were temporarily suspended or were in the process of being completed at December 31, 2007.

United States The Gulf of Mexico continues to be a core area for us. At the end of 2007, we had interests in 71 blocks in the Gulf of Mexico, including 64 in the deepwater area. In October 2007, we were the high bidder on 27 blocks offered in the federal Outer Continental Shelf Lease Sale No. 205 conducted by the U.S. Minerals Management Service (MMS) and were awarded these leases in early 2008. Representing a total net investment of $222 million for us, 13 blocks were bid 100 percent by us, and the remaining 14 blocks were bid in conjunction with partners. Our plans call for initial drilling on some of these leases in 2009 or 2010. The contract for the rig has an initial term of two years with an option to extend for an additional two years.

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In 2007, we drilled the Droshky (previously named Troika Deep) deepwater discovery well. This well and two appraisal sidetrack wells are located on Green Canyon Block 244 in the Gulf of Mexico and we are in the process of drilling additional appraisal wells. We have secured an additional year of drilling rig capacity in 2009 for development drilling in anticipation of a 2008 project sanction. The timing of initial production from the Droshky discovery will be dependent upon delivery of key equipment and regulatory approvals, but could be as early as 2010. We hold a 100 percent working interest in the Drohsky discovery.

In late 2007, drilling of an appraisal well began on the Stones prospect (Walker Ridge Block 508) after a 2005 discovery. We hold a 30 percent outside-operated interest in the Stones prospect.

In 2001, a successful discovery well was drilled on the Ozona prospect (Garden Banks Block 515) in the Gulf of Mexico and, in 2002, two sidetrack wells were drilled. We are continuing to evaluate options to develop the Ozona prospect. Commercial terms have been secured for the tie-back and processing of Ozona production and we have been actively searching for a rig to drill the development well. We hold a 68 percent operated interest in the Ozona prospect.

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 February 2008, 27 discoveries on these blocks have been announced, including eight in 2007 and one in early 2008. These discoveries represent four potential development hubs. Four discoveries and one successful appraisal well form a planned development area in the northeastern portion of Block 31. Nine 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 our first potential development in the eastern area of that block.

Norway We hold interests in over 800,000 gross acres offshore Norway and plan to continue our exploration effort there. We hold a 28 percent outside-operated interest in the Gudrun field, located 120 miles off the coast of Norway, where we are focused on subsurface evaluation and assessing development concepts after a successful appraisal well in 2006. First production from Gudrun is expected in 2012. In 2007, we also continued to advance exploration opportunities in the Alvheim area, the first of which is expected to be drilled in 2009.

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 will begin collecting geophysical data in the first quarter of 2008. We expect to begin exploratory drilling in 2009.

In addition, we were awarded two study agreements and farmed into additional study agreements in Indonesia in 2007 which could lead to the acquisition of new leaseholds at a future lease sale.

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 or additional LNG markets are entered that require increased natural gas supply.

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 2007 included the drilling of eight wells, six 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.

United Kingdom During 2007, we acquired a 45 percent outside-operated interest in three exploratory onshore coal bed methane licenses in the United Kingdom, representing 128,000 gross acres. Three exploration wells have been drilled on two of the licenses and additional delineation and production testing is planned during 2008. We also plan to participate in the U.K. Onshore Licensing Round during 2008 to secure additional acreage.

In the U.K. portion of the North Sea, Marathon participated in a discovery in Block 204/23 adjacent to the Foinaven field. This Foinaven Southwest discovery encountered hydrocarbons and will be considered for a potential tieback to the nearby infrastructure.

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Ukraine In 2007, we signed a cooperation agreement with a Ukrainian partner to carry out a study in the Dneiper-Donets Basin in north central Ukraine. The joint study will be conducted over three years on an area of joint interest covering 10,000 square miles and could lead to the joint exploration for hydrocarbons.

Production (including development activities)

United States Our U.S. operations accounted for 32 percent of our 2007 worldwide net liquid hydrocarbon sales volumes and 52 percent of our worldwide net natural gas sales volumes.

During 2007, our net sales in the Gulf of Mexico averaged 25 mbpd of liquid hydrocarbons, representing 39 percent of our total U.S. net liquid hydrocarbon sales, and 28 mmcfd of natural gas, representing 6 percent of our total U.S. net natural gas sales. Net liquid hydrocarbon and natural gas sales in the Gulf of Mexico decreased from the prior year, mainly due to normal production rate declines. At year-end 2007, we held interests in seven producing fields and eight platforms in the Gulf of Mexico, of which we operate four platforms.

The majority of our sales volumes in the Gulf of Mexico come from the Petronius development in Viosca Knoll Blocks 786 and 830. We own a 50 percent outside-operated working interest in these blocks. The Petronius platform provides processing and transportation services to adjacent third-party fields. For example, Petronius processes the production from our Perseus field which commenced production in April 2005 and is located five miles from the platform.

We hold a 30 percent outside-operated working interest in the Neptune deepwater development on Atwater Valley Blocks 573, 574, 575, 617 and 618 in the Gulf of Mexico, 120 miles off the coast of Louisiana. The development plan for Neptune was sanctioned in 2005 and includes seven subsea wells tied back to a stand-alone mini-tension leg platform. Construction of the platform and facility continued through 2007 with first production expected at the end of the first quarter of 2008.

We believe that we are one of the largest natural gas producers in the Cook Inlet and adjacent Kenai Peninsula of Alaska. In 2007, our net natural gas sales from Alaska averaged 142 mmcfd, representing 30 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 20 mbpd and 114 mmcfd in 2007. 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 and Powder River Basin areas. Development of the Powder River Basin continued in 2007 with 170 operated wells drilled, which was up from the 119 wells drilled in 2006. Additional development of our southwest Wyoming interests continued in 2007 where we participated in the drilling of 30 wells.

We also have domestic natural gas operations in Oklahoma, east Texas and north Louisiana, with combined net sales of 148 mmcfd in 2007, and liquid hydrocarbon operations in the Permian Basin of southeast New Mexico and west Texas, with net sales of 12 mbpd in 2007.

We hold 320,000 acres in the Williston Basin (the Bakken shale formation) following the acquisition of an additional 70,000 acres in late 2007. 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 with approximately 350 locations to be drilled over the next four to five years. We currently have six operated drilling rigs running in our Bakken shale program and ended 2007 with a net production rate of 2,600 barrels of oil equivalent per day.

We hold a natural gas leasehold in the Piceance Basin of Colorado, located in Garfield County in the Greater Grand Valley field complex. The acreage is located near adjacent production. Our plans include drilling approximately 700 wells in the next ten years. Drilling and production commenced in late 2007.

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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. Our share of liquid hydrocarbon sales from the Brae area averaged 14 mbpd in 2007. Our share of Brae natural gas sales averaged 139 mmcfd, or 31 percent of our international natural gas sales volumes, in 2007 and decreased from the prior year as a result of natural field declines in the North and East Brae natural gas condensate fields.

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

The Brae group owns a 50 percent interest in the outside-operated Scottish Area Gas Evacuation (SAGE) system. The SAGE pipeline transports natural gas from the Brae area and the third-party Beryl area and has a total wet natural gas capacity of 1.1 billion cubic feet (bcf) per day. The SAGE terminal at St. Fergus in northeast Scotland processes natural gas from the SAGE pipeline and 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 an approximate 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. Our share of sales from the Foinaven fields averaged 17 mbpd of liquid hydrocarbons and 9 mmcfd of natural gas in 2007.

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 eight licenses.

We are the operator of the Alvheim complex located on the Norwegian Continental Shelf. This development 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. The complex consists of a floating production, storage and offloading vessel (FPSO) with subsea infrastructure. Produced oil will be transported by shuttle tanker and produced natural gas will be transported to the SAGE system using a new 14-inch, 24-mile cross border pipeline. The multipurpose shuttle tanker that has been modified to serve as the FPSO sailed from the shipyard in mid-February 2008 to undergo testing, after which it will proceed offshore for connection to the subsea infrastructure. The Alvheim development will initially include ten producing wells and two water disposal wells in the drilling program, which will continue through the fourth quarter of 2008. The nearby Vilje discovery, in which we own a 47 percent outside-operated working interest, will also be produced through the Alvheim FPSO. The two Vilje development wells were drilled and completed in 2007. First production from the Alvheim/Vilje development is expected at the end of the first quarter of 2008, weather permitting.

In early 2007, the Norwegian government approved a plan for development and operation to develop the Volund field as a subsea tie-back to the Alvheim FPSO. The Volund development will consist of one production well and one water disposal well, both of which will be drilled in the first half of 2009 with an additional two wells to be drilled in the latter part of 2009. The produced oil will be exported via the shuttle tankers discussed above, and the associated natural gas will be exported via the Alvheim-to-SAGE pipeline. The Volund development, in which we own a 65 percent working interest and serve as operator, is expected to begin production in 2009.

During 2007, net liquid hydrocarbon and natural gas sales in Norway from the Heimdal, Vale and Skirne fields averaged 2 mbpd and 29 mmcfd. We own a 24 percent outside-operated working interest in the Heimdal field, a 47 percent outside-operated working interest in the Vale field and a 20 percent outside-operated working interest in the Skirne field.

Ireland We own a 100 percent working interest in the Kinsale Head, Ballycotton and Southwest Kinsale natural gas fields and an 87 percent operated working interest in the Seven Heads natural gas field in the Celtic Sea offshore Ireland. Net natural gas sales in Ireland were 39 mmcfd in 2007. In June 2006, we were awarded the first commercial natural gas storage license in Ireland, which allows us to provide full third-party storage services from the Southwest Kinsale field. The unit has a total working volume of 7 bcf per annum. Both indigenous

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Kinsale natural gas and natural gas imported from a transmission system are injected and withdrawn from the facility under contractual arrangements that expire in April 2009. Additionally, natural gas produced from our other fields or purchased from other parties can be stored at Southwest Kinsale for future sale to customers.

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. Two wells have been completed, and three additional wells are planned to be completed in 2008. The main 20-inch offshore pipeline installation is also planned for 2008. Terminal construction is underway. The operator expects first production from the field in the fourth quarter of 2009.

Equatorial Guinea We own a 63 percent operated working interest in the Alba field offshore Equatorial Guinea and a 52 percent interest in an onshore liquefied petroleum gas (LPG) processing plant held through an equity method investee. During 2007, net liquid hydrocarbon sales averaged 45 mbpd, or 34 percent of our international liquid hydrocarbon sales volumes, and net natural gas sales averaged 228 mmcfd, or 51 percent of our international natural gas sales volumes. Net liquid hydrocarbon sales volumes in 2007 included 33 mbpd of condensate and 12 mbpd of LPG.

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. During 2007, a gross 130 mmcfd of dry natural gas was supplied to the methanol plant and a gross 268 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.

Libya Net liquid hydrocarbon sales in Libya averaged 45 mbpd in 2007 compared to 54 mbpd in 2006, of which a total of 8 mbpd were owed to our account upon the resumption of our operations in Libya. The 2007 net liquid hydrocarbon sales in Libya represented 34 percent of our international liquid hydrocarbon sales volumes. Net natural gas sales in Libya averaged 4 mmcfd in 2007.

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 10 mbpd of liquid hydrocarbons in 2007. 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

We hold an interest in an exploration and production license in Sudan. We suspended all operations in Sudan in 1985 due to civil unrest. We have had no employees in the country and have derived no economic benefit from those interests since that time. The U.S. government imposed sanctions against Sudan in 1997 and we have not made any payments related to Sudan since then. We have abided and will continue to abide by all U.S. sanctions related to Sudan. We have reached an agreement to transfer our interest in this license to the operator. Governmental approval of this transfer is expected in the first quarter of 2008.

We discovered the Ash Shaer and Cherrife natural gas fields in Syria in the 1980s. We have recognized no revenues in any period from activities in Syria and we impaired our entire investment in Syria in 1998. In 2006, the Syrian government approved the assignment of 90 percent of our interest in the Ash Shaer and Cherrife natural gas fields to a non-U.S. company. We closed the transaction on November 1, 2006, and received cash proceeds of $46 million. The remaining 10 percent interest was assigned to the same company on December 21, 2007, for $5 million.

The above discussion of the E&P segment includes forward-looking statements with respect to anticipated future exploratory and development drilling, the possibility of developing the Gudrun field offshore Norway, Blocks 31 and 32 offshore Angola, the Foinaven Southwest discovery in the U.K. portion of the North Sea and the Equatorial Guinea discoveries, the possibility of obtaining access to new leaseholds in Indonesia and additional coal bed methane licenses in the United Kingdom, joint exploration for hydrocarbons in the Ukraine and the timing of production from the Droshky discovery, the Gudrun discovery, the Neptune development, 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

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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 obtain or delay in obtaining necessary government and third-party approvals and permits. The possible developments on the Gudrun field, Blocks 31 and 32 offshore Angola, the Foinaven Southwest discovery 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 joint exploration for hydrocarbons in the Ukraine include results of technical studies and continued favorable investment climate. The above discussion of the E&P segment also includes forward-looking statements with respect to our intention to exit a license in Sudan which could be potentially impacted by a delay in receiving governmental approval. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Reserves

At December 31, 2007, our net proved liquid hydrocarbon and natural gas reserves totaled 1.225 billion boe, of which 42 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		
	2007	2006	2005	**2007**	2006	2005
Liquid Hydrocarbons *(Millions of barrels)*						
United States	**135**	150	165	**166**	172	189
Europe	**32**	35	39	**115**	108	98
Africa	**304**	381	368	**369**	397	373
Worldwide Continuing Operations	**471**	566	572	**650**	677	660
Discontinued Operations[(a)]			31			44
WORLDWIDE	**471**	566	603	**650**	677	704
Developed reserves as a percent of total net proved reserves	**72%**	84%	86%			
Natural Gas *(Billions of cubic feet)*						
United States	**761**	857	943	**1,007**	1,069	1,209
Europe	**173**	238	326	**382**	444	486
Africa	**1,515**	648	638	**2,061**	1,997	1,852
WORLDWIDE	**2,449**	1,743	1,907	**3,450**	3,510	3,547
Developed reserves as a percent of total net proved reserves	**71%**	50%	54%			
Total BOE *(Millions of barrels)*						
United States	**262**	293	322	**334**	350	390
Europe	**61**	75	93	**179**	182	179
Africa	**556**	489	475	**712**	730	682
Worldwide Continuing Operations	**879**	857	890	**1,225**	1,262	1,251
Discontinued Operations[(a)]			31			44
WORLDWIDE	**879**	857	921	**1,225**	1,262	1,295
Developed reserves as a percent of total net proved reserves	**72%**	68%	71%			

[a] Represents Marathon s Russian oil exploration and production businesses that were sold in June 2006.

Proved developed liquid hydrocarbon and natural gas reserves represented 72 percent of total proved reserves as of December 31, 2007, as compared to 68 percent as of December 31, 2006. Of the 346 million boe of proved undeveloped reserves at year-end 2007, 58 percent of the volume is associated with projects that have been included in proved reserves for more than three years while 17 percent of the proved undeveloped reserves were added during 2007.

During 2007, we added a total of 88 million boe of net proved liquid hydrocarbon and natural reserves, principally in Libya, Norway and the Piceance Basin of Colorado. We disposed of 0.2 million boe, while producing

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125 million boe. Of the total net proved reserve additions, 38 million boe were proved developed and 50 million boe were proved undeveloped reserves. During 2007, we transferred 109 million boe from proved undeveloped to proved developed reserves. Costs incurred for the periods ended December 31, 2007, 2006 and 2005 relating to the development of proved undeveloped liquid hydrocarbon and natural gas reserves, were $1.250 billion, $1.010 billion and $955 million. As of December 31, 2007, estimated future development costs relating to the development of proved undeveloped liquid hydrocarbon and natural gas reserves for the years 2008 through 2010 are projected to be $859 million, $376 million and $293 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 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 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 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 2006 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 180 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)	**2007**	2006	2005
United States[(b)]	**64**	76	76
Europe[(c)]	**33**	35	36
Africa[(c)]	**100**	112	52
Worldwide Continuing Operations	**197**	223	164
Discontinued Operations[(d)]		12	27
WORLDWIDE	**197**	235	191

Net Natural Gas Sales[(e)]			
(Millions of cubic feet per day)	**2007**	2006	2005
United States[(b)]	**477**	532	578
Europe[(f)]	**169**	197	224
Africa	**232**	72	92
WORLDWIDE	**878**	801	894

(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 Marathon s 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 47 mmcfd, 46 mmcfd and 38 mmcfd in 2007, 2006 and 2005.

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Productive and Drilling Wells

The following table sets forth productive wells and service wells as of December 31, 2007, 2006 and 2005, and drilling wells as of December 31, 2007.

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
2007								
United States	**5,864**	**2,111**	**5,184**	**3,734**	**2,737**	**700**	**37**	**11**
Europe	**54**	**20**	**76**	**41**	**29**	**11**	**5**	**3**
Africa	**964**	**161**	**13**	**9**	**99**	**18**	**6**	**1**
WORLDWIDE	**6,882**	**2,292**	**5,273**	**3,784**	**2,865**	**729**	**48**	**15**
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		
2005								
United States	5,724	2,029	5,254	3,696	2,723	827		
Europe	51	19	68	37	29	10		
Africa	926	155	13	8	97	18		
Other International	156	156			50	50		
WORLDWIDE	6,857	2,359	5,335	3,741	2,899	905		

(a) Includes active wells and wells temporarily shut-in. Of the gross productive wells, wells with multiple completions operated by Marathon totaled 303, 294 and 278 as of December 31, 2007, 2006 and 2005. 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.

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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]				
		2007	2006	2005
United States				
Development[b]	Oil	**9**	32	46
	Natural Gas	**172**	186	288
	Dry		5	4
	Total	**181**	223	338
Exploratory	Oil	**9**	3	2
	Natural Gas	**13**	8	17
	Dry	**12**	3	2
	Total	**34**	14	21
	Total United States	**215**	237	359
International				
Development[b]	Oil	**7**	51	68
	Natural Gas		1	2
	Dry			1
	Total	**7**	52	71
Exploratory	Oil	**3**	19	2
	Natural Gas	**1**		
	Dry	**2**	6	4
	Total	**6**	25	6
	Total International	**13**	77	77
	WORLDWIDE	**228**	314	436

(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.

Acreage

The following table sets forth, by geographic area, the developed and undeveloped exploration and production acreage that we held as of December 31, 2007.

Gross and Net Acreage

	Developed	Undeveloped	Developed and Undeveloped

(Thousands of acres)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
United States	1,107	837	2,055	1,450	3,162	2,287
Europe	424	349	1,251	515	1,675	864
Africa	12,977	2,150	2,843	691	15,820	2,841
Other International			1,722	994	1,722	994
WORLDWIDE	14,508	3,336	7,871	3,650	22,379	6,986

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 certain oil sands deposits in the Athabasca region and upgrades the bitumen to synthetic crude oil. The AOSP s initial asset is the mining and extraction operations of the Muskeg River mine located 45 miles north of Fort McMurray, Alberta,

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which began bitumen production in 2003, together with 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. As of December 31, 2007, we have rights to participate in developed and undeveloped leases totaling 46,000 net acres. We are entitled to participate in future expansion opportunities on other nearby oil sands leases owned by the operator and, prior to December 6, 2009, on any new lands acquired 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 high-quality, synthetic crude oils. Bitumen production from the mine is taken by pipeline to the Scotford upgrader, which uses hydro-conversion technology to upgrade the bitumen into two streams of synthetic crude oil (Premium Albian Synthetic and Albian Heavy Synthetic) and vacuum gas oil. The vacuum gas oil is sold to the operator under a long-term contract for use in its refinery adjacent to the upgrading facility. When the AOSP is operating at its current capacity, our net bitumen production is 30 mbpd, but operations were curtailed at the Scotford upgrader subsequent to the Western acquisition date due to a mid-November fire. 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. Net bitumen production averaged 4 mbpd for 2007, based on total volumes from the October 18, 2007 acquisition date over total days in the year. Bitumen production averaged 19 mbpd for the post-acquisition period.

As of December 31, 2007, our net proved bitumen reserves were estimated to be 421 million barrels. Proved reserves can be added as expansions are permitted, funding is approved and certain stipulations of the joint venture agreement are satisfied.

In 2006, the first fully-integrated expansion of the existing AOSP facilities was approved. The Phase 1 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 AOSP Phase 1 expansion is under construction and we anticipate that it will be complete in late 2010. Work is underway to determine the feasibility of additional AOSP expansion projects including pursuing regulatory approvals.

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 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 outside 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 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 above discussion of the Oil Sands Mining segment includes forward-looking statements concerning the anticipated completion of the AOSP expansion project. Factors which could affect the project include transportation logistics, availability of material and labor, unforeseen hazards such as weather conditions, delays in obtaining or conditions imposed by necessary government and third-party approvals and other risks associated with construction projects.

Refining, Marketing and Transportation

Refining

We own and operate seven refineries with an aggregate refining capacity of 1.016 million barrels per day (mmbpd) of crude oil. During 2007, our refineries processed 1.010 mmbpd of crude oil and 214 mbpd of other charge and blend stocks. The table below sets forth the location and daily throughput capacity of each of our refineries as of December 31, 2007. These capacity amounts increased 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.

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Crude Oil Refining Capacity

(Thousands of barrels per day)	
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 can process a wide variety of crude oils and produce typical refinery products, including reformulated and low-sulfur gasolines and ultra-low sulfur diesel fuel. We also produce asphalt cements, polymerized asphalt, asphalt emulsions and industrial asphalts. We manufacture petroleum pitch, primarily used in the graphite electrode, clay target and refractory industries. Additionally, we manufacture aromatics, aliphatic hydrocarbons, cumene, base lube oil, polymer grade propylene, maleic anhydride and slack wax.

Our refineries are integrated via pipelines, terminals and barges to maximize operating efficiency. The transportation links that connect our refineries allow the movement of intermediate products to optimize operations and the production of higher margin products. For example, naphtha may be moved from Texas City to Robinson where excess reforming capacity is available. Also, by shipping intermediate products between facilities during partial refinery shutdowns, we are able to utilize processing capacity that is not directly affected by the shutdown work.

Planned maintenance activities requiring temporary shutdown of certain refinery operating units, or turnarounds, are periodically performed at each refinery. We completed fluid catalytic cracking unit turnarounds at our Catlettsburg, Robinson and St. Paul Park refineries in 2007.

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)	**2007**	2006	2005
Gasoline	**646**	661	644
Distillates	**349**	323	318
Propane	**23**	23	21
Feedstocks and Special Products	**108**	107	96
Heavy Fuel Oil	**27**	26	28
Asphalt	**86**	89	85
TOTAL	1,239	1,229	1,192

In 2006, we approved an expansion of our Garyville, Louisiana refinery by 180 mbpd to 436 mbpd, at a projected cost of $3.2 billion (excluding capitalized interest). Construction commenced in early 2007 and continues on schedule with additional project construction phases commencing in early 2008. We expect to complete the expansion in late 2009. In 2007, we approved a heavy oil upgrading and expansion project at our Detroit, Michigan refinery, at a projected cost of $1.9 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 is expected to begin in the first half of 2008, subject to obtaining necessary environmental permits, and is expected to be completed in late 2010. When completed, these two expansion projects will increase our current total crude oil refining capacity by 19 percent.

Marketing

We are a supplier of gasoline and distillates to resellers and consumers within our market area in the Midwest, upper Great Plains, Gulf Coast and southeastern regions of the United States. In 2007, our refined products sales volumes totaled 21.6 billion gallons, or 1.410 mmbpd. The average sales price of our refined

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products in aggregate was $86.53 per barrel for 2007. 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)	**2007**	2006	2005
Gasoline	**791**	804	836
Distillates	**377**	375	385
Propane	**23**	23	22
Feedstocks and Special Products	**103**	106	96
Heavy Fuel Oil	**29**	26	29
Asphalt	**87**	91	87
TOTAL [(a)]	**1,410**	1,425	1,455
Average sales price (Dollars per barrel)	**$86.53**	$77.76	$66.42

(a) Includes matching buy/sell volumes of 24 mbpd and 77 mbpd in 2006 and 2005. 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 2007 and the remainder of 2006 than would have been reported under our previous accounting practices. See Note 2 to the consolidated financial statements.

The wholesale distribution of petroleum products to private brand marketers and to large commercial and industrial consumers and sales in the spot market accounted for 69 percent of our refined products sales volumes in 2007. We sold 49 percent of our gasoline volumes and 89 percent of our distillates volumes on a wholesale or spot market basis. Half of our propane is sold into the home heating market, with the balance being purchased by industrial consumers. Propylene, cumene, aromatics, aliphatics and sulfur are domestically marketed to customers in the chemical industry. Base lube oils, maleic anhydride, slack wax, extract and pitch are sold throughout the United States and Canada, with pitch products also being exported worldwide. We market asphalt through owned and leased terminals throughout the Midwest, upper Great Plains, Gulf Coast and southeastern regions of the United States. Our customer base includes approximately 750 asphalt-paving contractors, government entities (states, counties, cities and townships) and asphalt roofing shingle manufacturers.

We have blended ethanol with gasoline for over 15 years and increased our blending program in 2007, in part due to renewable fuel mandates. We blended 41 mbpd of ethanol into gasoline in 2007 and 35 mbpd in both 2006 and 2005. The future expansion or contraction of our ethanol blending program will be driven by the economics of the ethanol supply and changes in government regulations. We sell reformulated gasoline in parts of our marketing territory, primarily Chicago, Illinois; Louisville, Kentucky; northern Kentucky; Milwaukee, Wisconsin and Hartford, Illinois, and we sell low-vapor-pressure gasoline in nine states. We also sell biodiesel in Minnesota, Illinois and Kentucky.

As of December 31, 2007, we supplied petroleum products to about 4,400 Marathon branded-retail outlets located primarily in Ohio, Michigan, Indiana, Kentucky and Illinois. Branded retail outlets are also located in Georgia, Florida, Minnesota, Wisconsin, North Carolina, Tennessee, West Virginia, Virginia, South Carolina, Alabama, Pennsylvania, and Texas. Sales to Marathon-brand jobbers and dealers accounted for 16 percent of our refined product sales volumes in 2007.

Speedway SuperAmerica LLC (SSA), our wholly-owned subsidiary, sells gasoline and diesel fuel primarily through retail outlets that we operate. Sales of refined products through these SSA retail outlets accounted for 15 percent of our refined products sales volumes in 2007. As of December 31, 2007, SSA had 1,636 retail outlets in nine states that sold petroleum products and convenience store merchandise and services, primarily under the brand names Speedway and SuperAmerica. SSA s revenues from the sale of non-petroleum merchandise totaled $2.796 billion in 2007, compared with $2.706 billion in 2006. Profit levels from the sale of such merchandise and services tend to be less volatile than profit levels from the retail sale of gasoline and diesel fuel. SSA also operates 59 Valvoline Instant Oil Change retail outlets located in Michigan and northwest Ohio.

Pilot Travel Centers LLC (PTC), our joint venture with Pilot Corporation (Pilot), is the largest operator of travel centers in the United States with 286 locations in 37 states and Canada at December 31, 2007. The travel centers offer diesel fuel, gasoline and a variety of other services, including on-premises brand-name restaurants at many locations. Pilot and Marathon each own a 50 percent interest in PTC.

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Our retail marketing strategy is focused on SSA s Midwest operations, additional growth of the Marathon brand and continued growth for PTC.

Supply and Transportation

We obtain most of the crude oil we refine from negotiated contracts and purchases or exchanges on the spot market. In 2007, U.S.-sourced crude oil averaged 527 mbpd, or 52 percent, of the crude oil processed at our refineries, including a net 15 mbpd from our production operations included in the E&P segment. Canada was the source for 14 percent, or 138 mbpd, of crude oil processed in 2007. Other foreign sources supplied 34 percent, or 345 mbpd, of the crude oil processed by our refineries, including 180 mbpd from the Middle East. This crude oil was acquired from various foreign national oil companies, producing companies and trading companies. The following table provides information on the sources of crude oil for each of the last three years.

Sources of Crude Oil Refined

(Thousands of barrels per day)	**2007**	2006	2005
United States	**527**	470	447
Canada	**138**	130	111
Middle East and Africa	**253**	266	301
Other International	**92**	114	114
TOTAL	**1,010**	980	973
Average cost of crude oil throughput *(Dollars per barrel)*	**$ 71.20**	$ 61.15	$ 51.85

We operate a system of pipelines, terminals and barges to provide crude oil to our refineries and refined products to our marketing areas. At December 31, 2007, we owned, leased, operated or held equity method investments in 68 miles of crude oil gathering lines, 3,717 miles of crude oil trunk lines and 3,860 miles of refined products trunk lines.

Excluding equity method investees, our owned or operated 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)	**2007**	2006	2005
Crude oil gathering lines	**17**	17	18
Crude oil trunk lines	**1,500**	1,484	1,619
Refined products trunk lines	**1,175**	1,101	1,219
TOTAL	**2,692**	2,602	2,856

At December 31, 2007 we had interests in the following pipelines:

100 percent ownership of Ohio River Pipe Line LLC, which owns a refined products pipeline extending from Kenova, West Virginia to Columbus, Ohio, known as Cardinal Products Pipeline;

60 percent interest in Muskegon Pipeline LLC, which owns a refined products pipeline extending from Griffith, Indiana to North Muskegon, Michigan;

51 percent interest in LOOP LLC (LOOP), the owner and operator of 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;

50 percent interest in Centennial Pipeline LLC, which owns a refined products system connecting Gulf Coast refineries with the Midwest market;

37 percent interest in the Capline system, a large-diameter crude oil pipeline extending from St. James, Louisiana to Patoka, Illinois;

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17 percent interest in Explorer Pipeline Company, a refined products pipeline system extending from the Gulf of Mexico to the Midwest;

17 percent interest in Minnesota Pipe Line Company, LLC, which owns a crude oil pipeline extending from Clearbrook, Minnesota to Cottage Grove, Minnesota, which is in the vicinity of our St. Paul Park, Minnesota refinery; and

6 percent interest in Wolverine Pipe Line Company, a refined products pipeline system extending from Chicago, Illinois to Toledo, Ohio.

Our 85 owned and operated light product and asphalt terminals are strategically located throughout the Midwest, upper Great Plains and southeastern United States. In October 2007, we executed an agreement to purchase four light product terminals in Ohio and an ownership interest in a refined product pipeline. This transaction is expected to close by the end of the second quarter of 2008, pending completion of various pre-closing activities, including obtaining necessary government approvals.

Our marine transportation operations include 15 towboats and 182 barges that transport refined products on the Ohio, Mississippi and Illinois rivers, their tributaries and the Intercoastal Waterway. We lease and own over 2,500 rail cars of various sizes and capacities for movement and storage of petroleum products and over 150 tractors and tank trailers.

Ethanol Production

In 2007, we acquired a 35 percent interest in an entity which owns and operates a 110-million-gallon-per-year ethanol facility in Clymers, Indiana, and continued construction of another 110-million-gallon-per-year ethanol facility in Greenville, Ohio. The Greenville plant, in which we own a 50 percent interest, began production in February 2008. Both of these facilities are managed by our partner, The Andersons, Inc. and will enable us to maintain the reliability of a portion of our future ethanol supplies.

The above discussion of the RM&T segment 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. The above discussion also includes forward-looking statements concerning the purchase of four terminals and an interest in a pipeline which is subject to customary closing conditions and may be affected by the inability or delay in obtaining necessary regulatory approvals and other operating and economic considerations. These factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

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 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 an FOB Bioko Island basis, 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 1,464,088 metric tonnes in 2007.

In 2007 we completed those portions of the front-end engineering and design (FEED) required to support the near-term efforts related to a potential second LNG production facility on Bioko Island, Equatorial Guinea. The scope of the FEED work for the potential 4.4 mmtpa LNG project included feed gas metering, liquefaction, refrigeration, ethylene storage, boil-off gas compression, product transfer to storage and LNG product metering. We expect to make progress towards an investment decision in 2008.

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We also own a 30 percent interest in a Kenai, Alaska, natural gas liquefaction plant, which is accounted for under the equity method of accounting, and have an undivided interest in a long-term lease for 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. This contract continues through March 2009, with 2007 LNG deliveries totaling 48 bcf. In January 2007, along with our partner, we filed a request with the DOE to extend the export license for this natural gas liquefaction plant through March 2011. This application has received favorable support from the State of Alaska but still requires final DOE approval.

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 1,060,653 metric tonnes in 2007. Production from the plant is used to supply customers in Europe and the United States.

Natural Gas Technology

We invest in natural gas technology research, including proprietary Gas-To-Fuels (GTF) technology which 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. We have designed and are constructing a 10-bpd demonstration facility for this technology, with initial startup scheduled for the second half of 2008. Expectations for the demonstration plant include the ability to demonstrate operations of the fully integrated process at a practical scale and to measure the conversion efficiencies of the total process, catalyst performance and materials durability. This critical performance data will support scale-up cost estimates for a commercial installation and provide the basis for continued technical developments in this area. 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 (GTL) 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.

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 on industry sources, we rank eighth among U.S.-based petroleum companies on the basis of 2006 worldwide liquid hydrocarbon and natural gas production.

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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. In addition, not all refineries are able to process or refine synthetic crude oil. 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. We rank fifth among U.S. petroleum companies on the basis of U.S. crude oil refining capacity as of December 31, 2007. We compete in four distinct markets wholesale, spot, branded and retail distribution for the sale of refined products. We believe we compete with about 40 companies in the wholesale distribution of petroleum products to private brand marketers and large commercial and industrial consumers; about 75 companies in the sale of petroleum products in the spot market; ten refiner/marketers in the supply of branded petroleum products to dealers and jobbers; and approximately 275 petroleum product retailers in the retail sale of petroleum products. 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. Some locations also have on-premises brand-name restaurants such as Subway . We also compete in the travel center industry through our 50 percent ownership in PTC.

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.

The Separation

On December 31, 2001, pursuant to an Agreement and Plan of Reorganization dated as of July 31, 2001, Marathon completed the 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 Separation, Marathon and United States Steel are separate companies and neither has any ownership interest in the other.

In connection with the 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 Separation and providing for the allocation of tax and certain other liabilities and obligations arising from periods before the Separation. The following is a description of the material terms of two of those agreements.

Financial Matters Agreement

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

- obligations under industrial revenue bonds related to environmental projects for current and former U.S. Steel Group facilities, with maturities ranging from 2009 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

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certain other guarantees.

The financial matters agreement also provides that, on or before the tenth anniversary of the 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 also requires United States Steel to use commercially reasonable efforts to have us released from our obligations under a guarantee we provided with respect to all of United States Steel s obligations under a partnership agreement between United States Steel, as general partner, and General Electric Credit Corporation of Delaware and Southern Energy Clairton, LLC, as limited partners. United States Steel may dissolve the partnership under certain circumstances, including if it is required to fund accumulated cash shortfalls of the partnership in excess of $150 million. In addition to the normal commitments of a general partner, United States Steel has indemnified the 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 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.

Obligations Associated with the Separation as of December 31, 2007

See Management s Discussion and Analysis of Financial Condition and Results of Operations Obligations Associated with the Separation of United States Steel for a discussion of our obligations associated with the Separation.

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 Responsibility 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 Marathon 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 both in the United States and abroad are in various stages of development. Our industry, and businesses 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. 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 refining crude oil and transportation crude oil and refined products. Although there may be adverse financial impact (including

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compliance costs, potential permitting delays and potential reduced demand for crude oil or certain products) associated with any legislation, regulation, EPA or other action, the extent and magnitude of impact cannot be reliably or accurately estimated due to newness of the requirements and the present uncertainty regarding the additional measures and how they will be implemented. 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 similar laws dealing with the same 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 always 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 Legal Proceedings and 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 now plan to spend approximately $350 million between 2006 and 2012 on refinery investments to produce ultra-low sulfur diesel fuel for off-road use, in compliance with EPA regulations. This is a forward-looking statement. Some factors (among others) that could potentially affect these compliance costs include final investment decisions, completion of project detailed engineering, construction and start-up activities. Further, we previously estimated that we would spend approximately $400 million over a four-year period beginning in 2008 to comply with Mobile Source Air Toxics II regulations relating to benzene. We have not finalized our strategy or cost estimates to comply with these recently promulgated requirements, but the cost estimates will increase and may be approximately $1 billion over a three-year period beginning in 2008. The cost estimates have increased due to better definition of the projects needed to meet the requirements of the finalized regulations and updated construction cost estimates. The cost estimates are forward-looking statements and are subject to change as FEED work is completed in 2008.

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 CAIR obligations by requiring emissions reductions from electric generating units, states will have the final say on what sources they regulate to meet attainment criteria. Our refinery operations are located in affected states and some of these states may choose to propose more stringent fuels requirements to meet the CAIR. Also, on July 11, 2007, the EPA proposed a revised ozone standard. Once the revised ozone standard is promulgated, the EPA will begin 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 states have taken further action and we cannot reasonably estimate the final financial impact of the revised ozone standard until the implementing rules are established.

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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 such releases OPA-90 requires responsible companies to pay resulting removal costs and damages, 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. Several 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 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. Ongoing RCRA-related costs, however, are not expected to be material. In addition, Canada will be implementing a ban on the land application of certain wastes and we are reviewing options to treat or dispose of these wastes consistent with these new restrictions.

Remediation

We own or operate certain retail outlets where, during the normal course of operations, releases of petroleum 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 Legal Proceedings Environmental Proceedings Other Proceedings for a discussion of these sites.

Other Matters

The Energy Policy Act of 2005 established a Renewable Fuel Standard (RFS) providing that all gasoline sold in the United States contain a minimum of 4.0 billion gallons of renewable fuel in 2006. The RFS increases gradually each year until 2012, when the RFS will be 7.5 billion gallons of renewable fuel. The EPA issued a final rule in May 2007 and the program went into effect on September 1, 2007. We have put the necessary systems in place to track and report our compliance with these requirements.

The recently-passed Energy Independence and Security Act of 2007 contains multiple RFSs. The overall requirement starts with 9.0 billion gallons of renewable fuel required in 2008 and ramps up to 36.0 billion gallons in 2022. Inside of the overall requirement is an advanced biofuels mandate which begins in 2009 and increases to 21.0 billion gallons by 2022. Subsets within the advanced biofuels requirements require 1.0 billion gallons of biomass-based diesel fuel by 2012 and 16.0 billion gallons of cellulosic ethanol by 2022. The EPA has not yet issued a proposal and a final rule to implement this program. This program presents specific challenges in that a refiner like us may have to enter into arrangements with other parties to meet its obligations to use advanced biofuels and cellulosic ethanol if it cannot produce these fuels itself. We may also experience a decrease in demand of our current refinery-produced petroleum products to the extent they are replaced by advanced biofuels and cellulosic

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ethanol and overall demand does not increase to replace this loss. There will be compliance costs and uncertainties regarding how we will comply with the mandates contained in this law and rule, but the extent and magnitude of impact cannot be reliably or accurately estimated due to the uncertainty of these measures at this time. We are and will be developing potential strategies for compliance with such requirements.

Employees

We had 29,524 active employees as of December 31, 2007. Of that number, 19,578 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, 2009. The same union represents certain hourly employees at our Texas City refinery under a labor agreement that expires on March 31, 2009. The International Brotherhood of Teamsters represents certain hourly employees under labor agreements that are scheduled to expire on May 31, 2009 at our St. Paul Park refinery and January 31, 2010 at our Detroit refinery.

Executive Officers of the Registrant

The executive officers of Marathon and their ages as of February 1, 2008, are as follows:

Philip G. Behrman	57	Senior Vice President, Worldwide Exploration
Clarence P. Cazalot, Jr.	57	President and Chief Executive Officer
Janet F. Clark	53	Executive Vice President and Chief Financial Officer
Gary R. Heminger	54	Executive Vice President
Steven B. Hinchman	49	Senior Vice President, Worldwide Production
Jerry Howard	59	Senior Vice President, Corporate Affairs
Paul C. Reinbolt	52	Vice President, Finance and Treasurer
David E. Roberts	47	Senior Vice President, Business Development
William F. Schwind, Jr.	63	Vice President, General Counsel and Secretary
Michael K. Stewart	50	Vice President, Accounting and Controller
Howard J. Thill	48	Vice President, Investor Relations and Public Affairs

With the exception of Ms. Clark and 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. Behrman was appointed senior vice president, worldwide exploration effective January 2002.

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, prior to which she was employed by Nuevo Energy Company from 2001 to December 2003 as senior vice president and chief financial officer.

Mr. Heminger was appointed executive vice president 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.

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. 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. He served as advisor to the vice chairman of ChevronTexaco Corporation from 2001 to 2003.

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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. Prior to his appointment as director of investor relations, Mr. Thill was manager of investor relations from January 2002 to March 2003.

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/.

Marathon s 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

Marathon is subject to various risks and uncertainties in the course of its business. The following summarizes some, but not all, of the 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, as well as 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;
- 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 climatic changes;
- natural disasters such as hurricanes and tornados;
- the price and availability of alternative and competing fuels;
- 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, as well as lower refining and wholesale marketing gross margins, may 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 and/or third-party consultants we have retained. The estimates were calculated using liquid hydrocarbon and natural gas prices in effect as of December 31, 2007, 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, 2007 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. 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; and
- the ability to find or acquire additional proved reserves at acceptable costs.

Increases in crude oil prices and environmental or other regulations may reduce our 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 attendant to doing business with suppliers located in that area of the world. Our overall RM&T 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.

In addition, various regulations have imposed, and are expected to continue to impose, increasingly stringent and costly requirements on our refining, marketing and transportation operations, which may reduce our refining and wholesale marketing gross margins.

We will continue to incur substantial capital expenditures and operating costs as a result of compliance with, and changes in environmental 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. 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 reasonably likely that the scientific and political attention to issues concerning the existence and extent of climate change will continue, with the potential for further regulations that could affect our operations. Although uncertain, these developments could increase costs or reduce the demand for the products we sell.

Our operations and those of our predecessors could expose us to civil claims by third parties for alleged liability resulting from contamination of the environment or personal injuries caused by releases of hazardous substances.

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

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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.

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 59 percent of our liquid hydrocarbon and natural gas sales volumes in 2007 was derived from production outside the United States and 73 percent of our proved liquid hydrocarbon and natural gas reserves as of December 31, 2007 were located outside the United States. All of our bitumen production and proved reserves are located in Canada.

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.

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. Actions by both the United States and host governments have affected operations significantly in the past 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, inclement 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 and damage or loss from severe weather conditions. These hazards could result in 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 litigation arising 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 these 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 materially

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reduce our profitability. Historically, we have maintained insurance coverage for physical damage and resulting business interruption to our major onshore and offshore facilities. 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.

We may not be successful in integrating and optimizing assets acquired in our acquisition of Western.

Risks associated with acquisitions include those relating to:

- liability for known or unknown environmental conditions or other contingent liabilities not covered by indemnification or insurance;
- greater than anticipated expenditures required for compliance with environmental or other regulatory standards, or for investments to improve operating results;
- difficulties in achieving anticipated operational improvements;
- diversion of management time and attention from our existing businesses and other priorities; and
- difficulties in integrating the financial, technological and management standards, processes, procedures and controls of an acquired business into those of our existing operations.

Such acquisition risks are in addition to any risks inherent in the operations of an oil sands mining business.

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.

Marathon is 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:

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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% (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 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 the interest in MPC, and either of those results could have a material adverse effect on us.

In a bankruptcy case or lawsuit initiated by one or more creditors or a representative of creditors of Ashland, a court 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 our 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 coverages. 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 $533 million as of December 31, 2007, 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.

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

As of the date of this filing, we have no unresolved comments from the staff of the Securities and Exchange Commission.

Item 2. Properties

The location and general character of the principal liquid hydrocarbon and natural gas properties, oil sands mining properties and facilities, refineries, pipeline systems and other important physical properties of Marathon have been described by segment under 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

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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 Financial Statements and Supplementary Data Supplemental Statistics. Estimated net proved liquid hydrocarbon and natural gas reserves are set forth in 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 Business Oil Sands Mining. The basis for estimating these reserves is discussed in 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

Marathon is 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 Marathon will remain a viable and competitive enterprise even though it is possible that these contingencies could be resolved unfavorably.

Natural Gas Royalty Litigation

As of December 31, 2005, Marathon had been served 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 plaintiff states that he sues for himself, as well as the state government. The Department of Justice has announced that it would intervene or has reserved judgment on whether to intervene against specified oil and gas companies and also announced that it would not intervene against certain other defendants including Marathon. One of the cases, U.S. ex rel Jack J. Grynberg v. Alaska Pipeline Co., et al, which was primarily a gas measurement case, was dismissed as to Marathon on October 20, 2006 on jurisdictional grounds. The second case, U.S. ex rel Harrold E. Wright v. Agip Petroleum Co. et al, is primarily a gas valuation case. The Wright case is in the discovery phase.

In October 2006, Marathon was served with an additional qui tam case, filed in the Western District of Oklahoma, which alleges that Marathon violated the False Claims Act by failing to pay the government past due interest resulting from royalty adjustments for crude oil, natural gas and other hydrocarbon production. The case is styled United States of America ex rel. Randy L. Little and Lanis G. Morris v. ENI Petroleum Co., et al. This case asserts that Marathon and other defendants are liable for past due interest, penalties, punitive damages and attorneys fees. Other than the allegation of a $1,360 underpayment for the month of May 2003, the parties in interest (Randy L. Little and Lanis G. Morris) have plead general damages with no other specific amounts against Marathon. Marathon intends to continue to vigorously defend these cases.

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 progress through the courts, the Wyoming BLM continues to process permits to drill under the ROD.

In the Environmental Defense Fund (EDF) v. BLM case before the Federal District Court of Wyoming, the EDF alleged that in 2002, the BLM did not sufficiently evaluate the air impacts associated with coal bed natural gas production in the Powder River Basin, as well as other oil and gas operations in Wyoming. Marathon and other producers had intervened. In June 2007, the Federal District Court for the District of Wyoming dismissed the EDF case (without prejudice as to refiling).

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MTBE Litigation

Marathon is a defendant along with many other refining companies in over 50 cases in 12 states alleging methyl tertiary-butyl ether (MTBE) contamination in groundwater. All of these cases, after their removal from state to federal court, have been consolidated in a multi-district litigation (MDL) in the Southern District of New York for pretrial proceedings. The plaintiffs generally are water providers or governmental authorities and they allege that refiners, manufacturers and sellers of gasoline containing MTBE are collectively liable, under market share and/or other alternative liability theories, for manufacturing a defective product. Several of these lawsuits allege contamination in areas that are outside of Marathon s marketing area. All of the cases seek punitive damages or treble damages under a variety of statutes and theories. In one of the cases, the State of New Jersey is seeking natural resources damages allegedly resulting from contamination of groundwater by MTBE. This is the only case in which Marathon is a defendant and natural resources damages are sought. Marathon stopped producing MTBE at its refineries in October 2002.

The MDL court has identified four test cases to proceed ahead of the remaining MDL cases. The first of these test cases (County of Suffolk (NY) and Suffolk County Water Authority v. Amerada Hess Corporation, et al.) is scheduled for trial in September 2008. Marathon is a defendant in this test case. Marathon is engaged in ongoing settlement discussions related to the majority of the cases in which it is defendant, including the Suffolk County, New York test case, and such settlement, if any, is not expected to significantly impact Marathon s consolidated results of operations, financial position or cash flows.

Product Contamination Litigation

A lawsuit was filed in the United States District Court for the Southern District of West Virginia and alleges that Marathon s Catlettsburg, Kentucky refinery sold defective gasoline to wholesalers and retailers, causing permanent damage to storage tanks, dispensers and related equipment, resulting in lost profits, business disruption and personal and real property damages. Class action certification was granted in August 2007. In 2002, Marathon conducted extensive cleaning operations at affected facilities and denies that any permanent damages resulted from the incident. Marathon previously settled with many of the potential class members in this case and intends to vigorously defend this action.

Environmental Proceedings

U.S. EPA Litigation

In 2002, Marathon and the American Petroleum Institute (API) brought a petition before the U.S. District Court for the District of Columbia, challenging the U.S. EPA s 2002 promulgation of new Oil Spill Prevention, Countermeasures and Control regulations on several grounds; while the dispute has been settled, the one remaining count is over the U.S. EPA s regulatory definition of waters covered by the Clean Water Act. Marathon and API contend that the U.S. EPA s regulations run contrary to recent decisions of the U.S. Supreme Court which, in finding federal agencies had gone greatly beyond the intentions of Congress as to what waters were covered by the Clean Water Act, narrowed the universe of what waters the federal government, rather than state governments, had jurisdiction to regulate. The case is ongoing with oral arguments to be heard in February 2008.

In September 2006, Marathon 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. These September 2006 actions have been consolidated with our pending April 2006 action against the U.S. EPA in the same court. The water quality amendments at issue, if approved, 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. The court has stayed this case while the U.S. EPA mediates the matter between Montana, Wyoming and the Northern Cheyenne tribe. Mediation and settlement talks continue while the litigation is on hold.

Montana Litigation

In June 2006, Marathon 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,

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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 is now being appealed to the Montana Supreme Court and does not impact Marathon operations in the meanwhile.

Wyoming Proceedings

The Wyoming Environmental Quality Council (EQC), which oversees the State Department of Environmental Quality (DEQ), has before it an administrative petition filed by the Powder River Basis Resource Council in 2006 seeking new water quality sulfate and barium standards for coal bed methane produced water and a requirement that all such water be beneficially reused. The petition seeks to expand the authority of the DEQ to regulate the quantity of water discharges. It would narrow the definition of required beneficial use discharges and would impose stricter effluent standards for discharged water. The EQC is also considering adoption of a rule which would impose more stringent water quality limits as to produced water discharges that come from any new coal bed methane or conventional oil and gas operations. The DEQ made this proposal citing a statutory directive that all waters that are suitable for agriculture may not be degraded. Marathon contends that its waters as currently regulated are beneficial to crops and livestock, rather than being a potential threat. The EQC would have to decide how stringent a water quality standard it would adopt for new discharges.

In response to the Governor of Wyoming s veto of a state agency adoption of a rule that would allow the DEQ to regulate the quantity of coal bed methane water discharges, an activist group has sued in state court to overturn the veto. In June 2007, Marathon and another producer filed a motion to intervene. The DEQ has begun issuing renewal water discharge and other permits with stringent limits based on its agricultural use policy rather than upon any regulation. The permits could require more costly water treatment or injection. Marathon is appealing every permit issued in this way. In 2007, the state court dismissed the activist group s lawsuit, and its time for appeal has expired.

Other Environmental Proceedings

The following is a summary of proceedings involving Marathon that were pending or contemplated as of December 31, 2007 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, Marathon is unable to reasonably estimate its 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, 2007, Marathon had been identified as a PRP at a total of ten CERCLA waste sites. Based on currently available information, which is in many cases preliminary and incomplete, Marathon believes that its liability for clean-up and remediation costs in connection with five of these sites will be under $1 million per site (with four of these five sites being under $100,000 each). As to the remaining five sites, Marathon believes that its liability for clean-up and remediation costs in connection with two of these sites will be under $4 million per site. Marathon is not far enough along in the process to determine the cost for the remaining three sites, but two of the sites may be $1 million to $2 million or more each and the other may be under $1 million. In addition, there are two sites for which Marathon has received information requests or other indications that it may be a PRP under CERCLA, but for which sufficient information is not presently available to confirm the existence of liability.

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There are also 119 sites, excluding retail marketing outlets, related to Marathon where remediation is being sought under other environmental statutes, both federal and state, or where private parties are seeking remediation through discussions or litigation. Based on currently available information, which is in many cases preliminary and incomplete, Marathon believes that its liability for clean-up and remediation costs in connection with 17 of these sites will be under $100,000 per site, that 54 sites have potential costs between $100,000 and $1 million per site and that 19 sites may involve remediation costs between $1 million and $5 million per site. Nine sites have incurred remediation costs of more than $5 million per site and there are six sites with insufficient information to estimate future remediation costs. There are 14 other sites for which Ashland retains responsibility to Marathon for remediation, subject to caps and other requirements contained in the agreements with Ashland related to Marathon s acquisition of Ashland s minority interest in MPC in 2005. Marathon estimates that it will be responsible for nearly $8 million in remediation costs at these sites which will not be reimbursed by Ashland, and Marathon has included this amount in its 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 29 years, Marathon anticipates spending approximately $6 million in remediation costs at this site. In 2008, 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 2007 and 2006 were $524,000 and $461,000, with expenditures for remedial measures in 2008 expected to be approximately $2 million.

MPC has had 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.

During 2001, Marathon entered into a New Source Review consent decree and settlement of alleged Clean Air Act and other violations with the EPA covering all of its refineries. The settlement committed Marathon to specific control technologies and implementation schedules for environmental expenditures and improvements to its refineries over approximately an eight-year period. In addition, Marathon has 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 substantially completed. As part of this consent decree, Marathon was required to conduct evaluations of its refinery benzene waste air pollution programs. These evaluations resulted in disclosure of benzene waste compliance issues at the Canton and Catlettsburg refineries. The U.S. Department of Justice has informed Marathon that it will seek several hundred thousand dollars of civil penalties (potentially to include supplemental environmental projects) for these matters. No formal enforcement action has been brought but Marathon will attempt to resolve these matters in 2008.

The U.S. Occupational Safety and Health Administration (OSHA) has announced a National Emphasis Program where it plans to inspect most of the domestic oil refinery locations. The inspections began in 2007 and focus on compliance with the OSHA Process Safety Management requirements. OSHA conducted an inspection at the Canton refinery over several months in 2007. This inspection resulted in an informal settlement agreement with OSHA in December 2007 under which a penalty of $321,500 was paid and Marathon agreed to various abatement measures. OSHA is scheduled to conduct an inspection of the Robinson refinery in the first quarter of 2008 and may conduct inspections of other Marathon refineries during that year. Further enforcement actions by OSHA may result from these inspections.

SEC Investigation Relating to Equatorial Guinea

By letter dated July 15, 2004, the SEC notified Marathon 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. This inquiry followed an investigation and public hearing conducted by the U.S. Senate Permanent Subcommittee on Investigations, which reviewed the transactions of various foreign governments, including those of Equatorial Guinea, with Riggs Bank. The investigation and hearing also reviewed the operations of U.S. oil and gas companies, including Marathon, in Equatorial Guinea. There was no finding in the Subcommittee s report that Marathon violated the U.S. Foreign Corrupt Practices Act or any other applicable laws or regulations. Marathon voluntarily produced documents requested by the SEC in that inquiry. On August 1, 2005, Marathon received a subpoena issued by the SEC pursuant to a formal order of investigation requiring the production of the documents that had already been produced or that were in the process of being identified and produced in response to the SEC s prior requests, and requesting the production of additional materials. Marathon has been and intends to continue cooperating with the SEC in this investigation.

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

Not applicable.

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 s common stock is traded is the New York Stock Exchange. Marathon s common stock is also traded on the Chicago Stock Exchange. Information concerning the quarterly high and low sales prices for the common stock as reported in the consolidated transaction reporting system and the frequency and amount of dividends paid during the last two years is set forth in Financial Statements and Supplementary Data Selected Quarterly Financial Data.

As of January 31, 2008, there were 59,638 registered holders of Marathon common stock.

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

Marathon s 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 its dividend policy with respect to Marathon common stock, the Board will rely on the consolidated financial statements of Marathon. Dividends on Marathon common stock are limited to legally available funds of Marathon.

Issuer Purchases of Equity Securities

The following table provides information about purchases by Marathon and its affiliated purchaser during the quarter ended December 31, 2007 of equity securities that are registered by Marathon pursuant to Section 12 of the Securities Exchange Act of 1934:

Period	(a) Total Number of Shares Purchased[(a)(b)]	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[(d)]	(d) Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs[(d)]
10/01/07 10/31/07	27,708	$ 57.10		$ 2,497,064,359
11/01/07 11/30/07	8,730	$ 58.86		$ 2,497,064,359
12/01/07 12/31/07	426,422[(c)]	$ 59.39	385,900	$ 2,474,099,898
Total	462,860	$ 59.24	385,900	

(a) 49,120 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 Marathon 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. Marathon acquired 22 shares due to acquisition share exchanges and Ashland share transfers pending at the closing of the transaction.

(c) 27,818 shares were repurchased in open-market transactions to satisfy the requirements for dividend reinvestment under the Marathon Oil Corporation Dividend Reinvestment and Direct Stock Purchase Plan (the Dividend Reinvestment Plan) by the administrator of the Dividend Reinvestment Plan. Stock needed to meet the requirements of the Dividend Reinvestment Plan are either purchased in the open market or issued directly by Marathon.

(d) In January 2006, Marathon announced a $2 billion share repurchase program which was increased by $500 million in both January and May 2007 and by $2 billion in July 2007, for a total authorized program of $5 billion. As of December 31, 2007, 58 million split-adjusted common shares had been acquired at a cost of $2.520 billion, which includes transaction fees and commissions that are not reported in the table above.

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Item 6. Selected Financial Data

(In millions, except per share data)	**2007**[(a)]	2006	2005[(b)]	2004	2003
Statement of Income Data:					
Revenues[(c)]	**$ 64,552**	$ 64,896	$ 62,986	$ 49,465	$ 40,907
Income from continuing operations	**3,948**	4,957	3,006	1,294	1,010
Net income	**3,956**	5,234	3,032	1,261	1,321
Basic per share data:					
Income from continuing operations	**$ 5.72**	$ 6.92	$ 4.22	$ 1.92	$ 1.63
Net income	**$ 5.73**	$ 7.31	$ 4.26	$ 1.87	$ 2.13
Diluted per share data:					
Income from continuing operations	**$ 5.68**	$ 6.87	$ 4.19	$ 1.91	$ 1.63
Net income	**$ 5.69**	$ 7.25	$ 4.22	$ 1.86	$ 2.13
Statement of Cash Flows Data:					
Capital expenditures from continuing operations	**$ 4,466**	$ 3,433	$ 2,796	$ 2,141	$ 1,873
Dividends paid	**637**	547	436	348	298
Dividends paid per share	**$ 0.92**	$ 0.76	$ 0.60	$ 0.51	$ 0.48
Balance Sheet Data as of December 31:					
Total assets	**$ 42,746**	$ 30,831	$ 28,498	$ 23,423	$ 19,482
Total long-term debt, including capitalized leases	**6,084**	3,061	3,698	4,057	4,085

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

(b) On June 30, 2005, Marathon acquired the 38 percent ownership interest in MPC previously held by Ashland, making it wholly-owned by Marathon. See Note 6 to the consolidated financial statements

(c) Effective April 1, 2006, Marathon changed its 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

Marathon is engaged in worldwide exploration, production and marketing of liquid hydrocarbons and natural gas; mining, extraction and transportation of bitumen from oil sands deposits in Alberta, Canada, and upgrading of the bitumen for the production and marketing of synthetic crude oil and by-products; domestic refining, marketing and transportation of crude oil and petroleum products, primarily in the Midwest, upper Great Plains, Gulf Coast and southeastern regions of the United States; and worldwide marketing and transportation of products manufactured from natural gas, such as LNG and methanol, and development of other projects to link stranded natural gas resources with key demand areas. Management s Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the information under Business, Risk Factors, Selected Financial Data and Financial Statements and Supplementary Data.

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 EGHoldings. As discussed in Note 4 to the consolidated financial statements, effective May 1, 2007, we no longer consolidate EGHoldings. Our investment is accounted for prospectively using the equity method of accounting. Unless specifically noted, amounts presented for the Integrated Gas segment for periods prior to May 1, 2007 include amounts related to the minority interests. Unless specifically noted, amounts for the RM&T segment include the 38 percent interest in MPC held by Ashland prior our acquisition of that interest on June 30, 2005.

Overview

Acquisition of Western Oil Sands Inc.

On October 18, 2007, we completed the acquisition of all the outstanding shares of Western for cash and securities of $5.833 billion. Western s debt was $1.063 billion at closing. Western s primary asset was a 20 percent outside-operated interest in the AOSP, which is 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.

Exploration and Production

Exploration and Production segment revenues correlate with prevailing prices for the various qualities of crude oil and natural gas we produce. Higher crude oil prices in 2007 primarily reflected increasing global demand and ongoing concerns about supplies of crude oil from oil-producing countries. During 2007, the average spot price per barrel for West Texas Intermediate (WTI), a benchmark crude oil, was $72.41, up from an average of $66.25 in 2006, and ended the year at $95.98. During 2007, the average spot price per barrel for Dated Brent (Brent), an international benchmark crude oil, was $72.39, up from an average of $65.14 in 2006, and ended the year at $96.02. The differential between WTI and Brent average prices narrowed to $0.02 in 2007 from $1.11 in 2006. 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 were lower in 2007 than in 2006. 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 $0.38 per thousand cubic feet (mcf) lower in 2007 than the 2006 average. Our natural gas prices in Alaska are largely contractual. Natural gas sales there are seasonal in nature, trending down during the second and third quarters of each year and increasing during the fourth and first quarters. Our other major natural gas-producing regions are Europe and Equatorial Guinea, where large portions of our natural gas are sold at contractual prices, making realized prices in these areas less volatile. The significant increase in sales of natural gas in Equatorial Guinea, at a fixed price, to the new LNG production facility discussed below contributed to the decrease in our average international realized natural gas prices.

For information on commodity price risk management, see Quantitative and Qualitative Disclosures about Market Risk.

E&P segment income during 2007 was down 14 percent from 2006, primarily as a result of lower liquid hydrocarbon sales volumes and natural gas realizations and increased exploration expenses, partially offset by higher liquid hydrocarbon realizations and natural gas sales volumes.

Oil Sands Mining

Our oil sands mining and bitumen upgrading operations were acquired in October 2007 as part of our acquisition of Western and are comprised of a 20 percent outside-operated interest in the AOSP, which includes the operating Muskeg River mine and the Scotford upgrader, located in Alberta, Canada. The bitumen production from the Muskeg River mine is taken by pipeline to the Scotford upgrader, which uses hydro-conversion technology to upgrade the bitumen into a range of high-quality, synthetic crude oils. When the AOSP is operating at current capacity, our net bitumen production is 30 mbpd, but operations were curtailed at the Scotford upgrader subsequent to the Western acquisition date due to a mid-November fire. 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.

Oil Sands Mining segment revenues correlate with prevailing prices for the various qualities of synthetic crude oil we produce and the cost of materials and supplies input during the upgrading process also correlate with market prices for commodities. The operating cost structure of the oil sands mining operations is predominantly fixed, and therefore many of the costs incurred when the AOSP is in full operation continue during any production downtime. This had a negative effect on segment income subsequent to the acquisition date as a result of the downtime associated with the fire and maintenance activities discussed above.

For information on commodity price risk management, see Quantitative and Qualitative Disclosures about Market Risk.

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.

The 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, the costs of purchased products and manufacturing expenses, including depreciation. As a result, our refining and wholesale marketing gross margin could be adversely affected by rising crude oil and other charge and blendstock prices that are not recovered in the marketplace. The crack spread, which is generally a measure of the difference between market prices for gasoline and distillate and crude oil costs, is a commonly used industry indicator of refining margins. In addition to changes in the crack spread, our refining and wholesale marketing gross margin is impacted by the types of crude oil and other charge and blendstocks we process, the selling prices we realize for all the refined products we sell, the cost of purchased products, our level of manufacturing costs and the impact of commodity derivative instruments we use in our RM&T operations primarily to mitigate price risk between the time that crude oil purchases are priced and when they are actually refined into salable petroleum products. We process significant amounts of sour crude oil which enhances our profitability compared to certain of our competitors as sour crude oil typically can be purchased at a discount to sweet crude oil. Over the last three years, 58 percent of the crude oil throughput at our refineries has been sour crude oil. As one of the largest U.S. producers of asphalt, our refining and wholesale marketing gross margin is also impacted by the selling price of asphalt. Sales of asphalt increase during the highway construction season in our market area, which is typically in the second and third quarters of each year. The selling price of asphalt is dependent on the cost of crude oil, the price of alternative paving materials and the level of construction activity in both the private and public sectors. We supplement our refining production by purchasing gasolines and distillates in the spot market to resell at wholesale. In addition, we purchase ethanol for blending with gasoline. Our refining and wholesale marketing gross margin is impacted by the cost of these

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purchased products, which varies with available supply and demand. Finally, our refining and wholesale marketing gross margin is impacted by changes in manufacturing costs from period to period, 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 refining and wholesale marketing gross margin has been historically volatile and varies with the level of economic activity in our various marketing areas, the availability of refined product supply, the regulatory climate, logistical capabilities and expectations regarding the adequacy of refined products, ethanol and raw material supplies.

Our 2007 refining and wholesale marketing gross margin was the key driver of the 26 percent decrease in RM&T segment income when compared to 2006. The average refining and wholesale marketing gross margin per gallon decreased to 18.48 cents in 2007 from 22.88 cents in 2006, primarily due to the significant and rapid increases in crude oil prices during 2007 and lagging wholesale price realizations.

For information on commodity price risk management, see Quantitative and Qualitative Disclosures about Market Risk.

Our seven refineries have an aggregate refining capacity of 1.016 mmbpd of crude oil. During 2007, our refineries processed 1.010 mmbpd of crude oil and 214 mbpd of other charge and blend stocks.

Our retail marketing gross margin for gasoline and distillates, which is the difference between the ultimate price paid by consumers and the cost of the refined products, including secondary transportation and consumer excise taxes, also plays an important part in RM&T segment profitability. Factors affecting our retail gasoline and distillate gross margin include competition, seasonal demand fluctuations, the available wholesale supply, the level of economic activity in our marketing areas and weather conditions that impact driving conditions. The gross margin on merchandise sold at retail outlets tends to be less volatile than the gross margin from the retail sale of gasoline and distillates. Factors affecting the gross margin on retail merchandise sales include consumer demand for merchandise items, the impact of competition and the level of economic activity in our marketing areas.

The profitability of our pipeline transportation operations is primarily dependent on the volumes shipped through the 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 driving season, which extends from May through September of each year, and declines during the fall and winter months. The seasonal pattern for distillates is the reverse of this, helping to level overall variability on an annual basis. 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 production facility in Equatorial Guinea that commenced operations during 2007 is a key component of this strategy. Our integrated gas operations include marketing and transportation of products manufactured from natural gas, such as LNG and methanol, primarily in the United States, Europe and West Africa. Methanol spot pricing is volatile largely because global methanol demand is 38 million tonnes and any major unplanned shutdown of or addition to production capacity can have a significant impact on the supply-demand balance. Also included in the financial results of the Integrated Gas segment are the costs associated with ongoing development of integrated gas projects, including natural gas technology research.

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2007 Highlights

We acquired Western and, as a result, added 421 million barrels of net proved bitumen reserves.

We announced the Droshky discovery and two appraisal sidetrack wells in the Gulf of Mexico and eight discoveries in deepwater Angola and continued our Alvheim/Vilje and Neptune development projects.

We added net proved liquid hydrocarbon and natural gas reserves of 88 million boe, while producing 125 million boe during 2007. Over the past three years, we have added net proved reserves of 516 million boe, excluding dispositions of 46 million boe, while producing 383 million boe.

We achieved record refinery crude oil and total throughput and strengthened our RM&T business by:

- Commencing construction of the Garyville, Louisiana, refinery expansion;
- Approving a heavy oil upgrading and expansion project at the Detroit, Michigan, refinery; and
- Continuing our investment in transportation and storage assets to increase our ethanol blending capacity throughout our terminal network and in ethanol production assets to further ensure the security of our supply of ethanol.

We completed construction of the Equatorial Guinea LNG production facility ahead of schedule and on budget and commenced operations.

We focused on total shareholder return by:

- Repurchasing 16 million common shares in 2007, bringing the total repurchases under our $5 billion program to 58 million common shares through 2007 at a cost of $2.520 billion;
- Increasing our quarterly dividend per share by 20 percent ; and
- Completing a two-for-one common stock split.

Critical Accounting Estimates

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

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

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, economic and political conditions change. During 2007, net revisions of previous estimates increased total proved reserves by 4 million boe (less than 1 percent of the beginning-of-the-year reserves estimate). Positive revisions of 32 million boe were partially offset by 28 million boe in negative revisions.

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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 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). Reserve estimates are reviewed and approved by members of 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 rank in the top 80 percent of our total reserves over a rolling four-year period. The volumes independently estimated are targeted to total at least 80 percent of our total reserves at the beginning of the fourth year. We met this goal for the four-year period ended December 31, 2007. 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 would adjust our reserve estimates as necessary. This independent third-party reserve estimation process did not result in significant changes to our reserve estimates in 2007, 2006 or 2005.

The reserves of the Alba field in Equatorial Guinea comprise 39 percent of our total proved liquid hydrocarbon and natural gas reserves as of December 31, 2007. The reserves of the next five largest asset groups the Waha concessions in Libya, the Alvheim/Vilje development offshore Norway, the Brae area complex offshore the United Kingdom, the Oregon Basin field in the Rocky Mountain area of the United States and the Petronius development on Viosca Knoll Blocks 786 and 830 in the Gulf of Mexico comprise 31 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 $0.66 per barrel, which would increase pretax income by approximately $85 million annually, based on 2007 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 $0.81 per barrel and would result in a decrease in pretax income of approximately $104 million annually, based on 2007 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.

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 allocating the Western acquisition purchase price and 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, 2007 were estimated using volumetric estimation techniques similar to those used in estimating liquid hydrocarbon and natural gas reserves. Proved bitumen reserves were estimated at October 18, 2007, the date of the Western acquisition, based on the third-party consultants estimate as of December 31, 2006, adjusted for production through the acquisition date.

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. A five percent

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increase in estimated bitumen reserves would lower the depreciation and depletion rate by approximately $0.70 per barrel, and a five percent decrease in estimated bitumen reserves would increase the depreciation and depletion rate by approximately $0.77 per barrel.

Fair Value Estimates

We are required to develop estimates of fair value to allocate the purchase prices paid to acquire businesses to the assets acquired and liabilities assumed in those acquisitions, to assess impairment of long-lived assets, goodwill and intangible assets and to record non-exchange traded derivative instruments. Other items that require fair value estimates include asset retirement obligations, guarantee obligations and stock-based compensation.

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. The most difficult estimations of individual fair values are those 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. During 2007, we made a significant acquisition with an aggregate purchase price of $5.833 billion that was allocated to the assets acquired and liabilities assumed based on their estimated fair values. See Note 6 to the consolidated financial statements for information on this acquisition. We did not make any significant acquisitions in 2006. As of December 31, 2007, our recorded goodwill was $2.899 billion. 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 its carrying value.

The fair values used to allocate the purchase price of an acquisition and to test goodwill for impairment are often estimated using the expected present value of future cash flows method, which requires us to project related future revenues and expenses 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 and unpredictable. Accordingly, actual results may differ from the projected results used to determine fair value.

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, expansion 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.

Estimating the expected future cash flows from our oil and gas producing asset groups and our oil sands mining and bitumen upgrading assets requires assumptions about matters such as future liquid hydrocarbon and natural gas prices, estimated recoverable quantities of liquid hydrocarbons, natural gas and bitumen, expected timing of production and the political environment in the host country. An impairment of any of our large oil and gas producing properties or our oil sands mining and bitumen upgrading assets could have a material impact on our consolidated financial condition and results of operations.

We evaluate our unproved property investment for 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 and/or future plans to develop acreage are also considered. The expected future cash flows from our RM&T assets require assumptions about matters such as future refined product prices, future crude oil and other feedstock costs, estimated remaining lives of the assets and future expenditures necessary to maintain the assets existing service potential.

Impairment charges have not been significant, totaling $19 million and $25 million in 2007 and 2006, while there were no impairment charges in 2005.

We record all derivative instruments at fair value. 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 expire in September 2009. These contracts 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

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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 next 18 months. Beginning in the second quarter of 2008, the remaining contract terms will be less than 18 months and therefore the forecasted valuation period will be reduced accordingly. 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. In 2007, 2006 and 2005, non-cash losses of $232 million, gains of $454 million and losses of $386 million related to changes in the fair values of these contracts were recognized in income from operations. These effects are primarily due to the U.K. 18-month forward natural gas price curve strengthening 45 percent in 2007, weakening 44 percent in 2006 and strengthening 90 percent in 2005.

Expected Future Taxable Income

We must estimate our expected future taxable income to assess the realizability of our deferred income tax assets. As of December 31, 2007, we reported total deferred tax assets of $2.589 billion, which represented gross assets of $3.590 billion net of valuation allowances of $1.001 billion.

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.

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 and possible 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 propriety of releasing an existing valuation allowance, we consider the preponderance of evidence concerning the realization of the impaired deferred tax asset.

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

Pension and Other Postretirement Benefit Obligations

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

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

We develop our demographics and utilize the work of third-party actuaries to assist in the measurement of these obligations. We have selected different discount rates for our funded U.S. pension plans and our unfunded U.S. retiree health care plan due to the different projected liability durations of 8 years and 12 years. 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.

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.

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

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

Note 24 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 2007, 2006 and 2005, as well as the obligations and accumulated other comprehensive income reported on the balance sheets as of December 31, 2007 and 2006.

Of the assumptions used to measure the December 31, 2007 obligations and estimated 2008 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 6.3 percent for our U.S. pension plans and 6.6 percent for our other U.S. postretirement benefit plans would increase pension obligations and other postretirement benefit plan obligations by $95 million and $23 million and would increase defined benefit pension expense and other postretirement benefit plan expense by $14 million and $1 million.

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. In 2005, we decreased our retirement age assumption by two years and also increased our lump sum election rate from 90 percent to 96 percent based on changing trends in our experience. This change increased our benefit obligations by $109 million. There were no plan design changes in 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.

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Management s Discussion and Analysis of Results of Operations

Change in Accounting for Matching Buy/Sell Transactions

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 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. Effective for contracts entered into or modified 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 will continue to be reported on a gross basis. This accounting change had no effect on net 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. See Note 2 to the consolidated financial statements.

Additionally, this accounting change impacts the comparability of certain operating statistics, most notably refining and wholesale marketing gross margin per gallon. While this change does not have an effect on the refining and wholesale marketing gross margin (the numerator for calculating this statistic), sales volumes (the denominator for calculating this statistic) recognized after April 1, 2006 are less than the amount that would have been recognized under previous accounting practices because volumes related to matching buy/sell transactions under contracts entered into or modified on or after April 1, 2006 have been excluded. Accordingly, the resulting refining and wholesale marketing gross margin per gallon statistic will be higher than that same statistic calculated from amounts determined under previous accounting practices.

As a result, this accounting change impacts the comparability of revenues, cost of revenues and the refining and wholesale marketing gross margin per gallon for all periods presented.

Consolidated Results of Operations

Revenues for each of the last three years are summarized in the following table.

(In millions)	**2007**	2006	2005
E&P	**$ 9,155**	$ 9,010	$ 8,009
OSM	**221**		
RM&T	**56,075**	55,941	56,003
IG	**218**	179	236
Segment revenues	**65,669**	65,130	64,248
Elimination of intersegment revenues	**(885)**	(688)	(876)
Gain (loss) on long-term U.K. gas contracts	**(232)**	454	(386)
Total revenues	**$ 64,552**	$ 64,896	$ 62,986
Items included in both revenue and costs and expenses:			
Consumer excise taxes on petroleum products and merchandise	**$ 5,163**	$ 4,979	$ 4,715
Matching crude oil and refined product buy/sell transactions settled in cash:			
E&P		16	123
RM&T	**127**	5,441	12,513
Total buy/sell transactions included in revenues	**$ 127**	$ 5,457	$ 12,636

E&P segment revenues increased $145 million in 2007 from 2006 and $1.001 billion in 2006 from 2005. 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 to the start-up of the LNG production facility in Equatorial Guinea 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.

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The 2006 increase was primarily in international revenues due to higher realized liquid hydrocarbon prices and sales volumes as illustrated in the table below. The largest liquid hydrocarbon sales volume increase was in Libya, where the first crude oil sales occurred in the first quarter of 2006 and where sales volumes averaged 54 mbpd in 2006, including a total of 8 mbpd that were owed to our account upon the resumption of our operations there. Revenues from domestic operations were flat from year to year. An 8 percent decrease in domestic net natural gas sales volumes, primarily as the result of the Camden Hills field in the Gulf of Mexico ceasing production in early 2006, offset the benefit of higher liquid hydrocarbon prices in 2006.

E&P OPERATING STATISTICS	**2007**	2006	2005
Net Liquid Hydrocarbon Sales *(thousands of barrels per day)*[(a)]			
United States	**64**	76	76
Europe[(b)]	**33**	35	36
Africa[(b)]	**100**	112	52
Total International[(b)]	**133**	147	88
Worldwide Continuing Operations	**197**	223	164
Discontinued Operations[(c)]		12	27
WORLDWIDE	**197**	235	191
Net Natural Gas Sales *(millions of cubic feet per day)*[(d)(e)]			
United States	**477**	532	578
Europe	**216**	243	262
Africa	**232**	72	92
Total International	**448**	315	354
WORLDWIDE	**925**	847	932
Total Worldwide Sales *(thousands of barrels of oil equivalent per day)*			
Continuing Operations	**351**	365	319
Discontinued Operations		12	27
WORLDWIDE	**351**	377	346
Average Realizations[(f)]			
Liquid Hydrocarbons *(dollars per barrel)*			
United States	**$ 60.15**	$ 54.41	$ 45.41
Europe	**70.31**	64.02	52.99
Africa	**66.09**	59.83	46.27
Total International	**67.15**	60.81	49.04
Worldwide Continuing Operations	**64.86**	58.63	47.35
Discontinued Operations		38.38	33.47
WORLDWIDE	**$ 64.86**	$ 57.58	$ 45.42
Natural Gas *(dollars per thousand cubic feet)*			
United States	**$ 5.73**	$ 5.76	$ 6.42
Europe	**6.53**	6.74	5.70
Africa	**0.25**	0.27	0.25
Total International	**3.28**	5.27	4.28
WORLDWIDE	**$ 4.54**	$ 5.58	$ 5.61

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

(b) 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.

(c) Represents Marathon s 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, 46 and 38 mmcfd in 2007, 2006 and 2005.

(f) Excludes gains and losses on traditional derivative instruments and the unrealized effects of long-term 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 and $7 million in 2006 and 2005. Excluded from E&P segment revenues were losses of $232 million in 2007, gains of $454 million in 2006 and losses of $386 million in 2005 related to long-term natural gas sales contracts in the United Kingdom that are accounted for as derivative instruments. See 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

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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 conjuction with the necessary repairs. The Scotford upgrader returned to operation in late December.

RM&T segment revenues increased $134 million in 2007 from 2006 and decreased $62 million in 2006 from 2005. The portion of RM&T revenues reported for matching buy/sell transactions decreased $5.314 billion and $7.072 billion in the same periods. 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. The 2006 increase primarily reflected higher refined product prices and sales volumes.

Income from equity method investments increased $154 million in 2007 from 2006 and $126 million in 2006 from 2005. 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. Income from our LPG operations, also in Equatorial Guinea, increased in 2006 due to higher sales volumes as a result of the plant expansions completed in 2005.

Cost of revenues increased $6.689 billion in 2007 from 2006 and $4.609 billion in 2006 from 2005. In both periods the increases were primarily in the RM&T segment and resulted from increases in acquisition costs of crude oil, refinery charge and blend stocks and purchased refined products. The increases in both periods were also impacted by higher manufacturing expenses, primarily planned maintenance projects, or turnarounds, in 2007 and higher contract services and labor costs in 2006.

Purchases related to matching buy/sell transactions decreased $5.247 billion in 2007 from 2006 and $6.968 billion in 2006 from 2005 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 and $215 million in 2006 from 2005. 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. The increase in 2006 included higher RM&T depreciation expense primarily as a result of the increase in asset value recorded for our acquisition of the 38 percent interest in MPC on June 30, 2005, and the completion of the Detroit refinery expansion in the fourth quarter of 2005.

Selling, general and administrative expenses increased $99 million in 2007 from 2006 and $73 million in 2006 from 2005. The 2007 and 2006 increases were primarily because personnel and staffing costs increased throughout the years as a result of variable compensation arrangements and increased business activity. Contingency accruals also contributed to the 2007 increase. Partially offsetting the 2006 increases were reductions in stock-based compensation expense.

Exploration expenses increased $89 million in 2007 from 2006 and $148 million in 2006 from 2005. Exploration expenses related to dry wells and other write-offs totaled $233 million, $166 million and $111 million in 2007, 2006 and 2005. In 2006, exploration expenses also included $47 million for exiting the Cortland and Empire leases in Nova Scotia.

Net interest and other financial income or costs reflected $41 million of income for 2007, a favorable change of $4 million from 2006. Net interest and other financial income or costs reflected $37 million of income for 2006, a favorable change of $183 million from $146 million of expense in 2005. The favorable changes in 2006 included increased interest income due to higher interest rates and average cash balances, foreign currency exchange gains, adjustments to interest on tax issues and greater capitalized interest. Included in net interest and other financial income or costs are foreign currency transaction gains of $2 million and $16 million for 2007 and 2006, and losses of $17 million for 2005.

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.

Minority interest in income of MPC was eliminated subsequent to our acquisition of the 38 percent interest in MPC on June 30, 2005.

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Provision for income taxes decreased $1.121 billion in 2007 from 2006 and increased $2.308 billion in 2006 from 2005, primarily due to the $2.130 billion decrease and the $4.259 billion increase 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 increase in our effective income tax rate in 2006 was primarily a result of the income taxes related to our Libya operations, where the statutory income tax rate is in excess of 90 percent. The following is an analysis of the effective income tax rates for continuing operations for 2007, 2006 and 2005. See Note 11 to the consolidated financial statements.

	2007	2006	2005
Statutory U.S. income tax rate	**35.0%**	35.0%	35.0%
Effects of foreign operations, including foreign tax credits	**9.8**	10.1	(0.8)
State and local income taxes, net of federal income tax effects	**2.0**	1.9	2.8
Effects of enacted changes in tax laws	**(2.8)**	(0.2)	(0.3)
Other tax effects	**(1.6)**	(2.0)	(0.4)
Effective income tax rate for continuing operations	**42.4%**	44.8%	36.3%

Discontinued operations for 2006 and 2005 reflects the operations of our former Russian oil exploration and production businesses which were sold in June 2006. After-tax gains on the disposal of $8 million and $243 million are also included in discontinued operations for 2007 and 2006. See Note 7 to the consolidated financial statements.

Cumulative effect of change in accounting principle in 2005 was an unfavorable effect of $19 million, net of taxes of $12 million, representing the adoption of Financial Accounting Standards Board Interpretation (FIN) No. 47, Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No. 143, as of December 31, 2005.

Segment Results

As discussed in Note 7 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 each of the last three years is summarized and reconciled to net income in the following table.

(In millions)	**2007**	2006	2005
E&P			
United States	**$ 623**	$ 873	$ 983
International	**1,106**	1,130	904
E&P segment income	**1,729**	2,003	1,887
OSM	**(63)**		
RM&T	**2,077**	2,795	1,628
IG	**132**	16	55
Segment income	**3,875**	4,814	3,570
Items not allocated to segments, net of income taxes:			
Corporate and other unallocated items	**(104)**	(212)	(377)
Gain (loss) on long-term U.K. natural gas contracts[(a)]	**(118)**	232	(223)
Gain on foreign currency derivative instruments	**112**		
Deferred income taxes tax legislation changes	**193**	21	15
other adjustments[(b)]		93	

Gain on dispositions	**8**	274	
Loss on early extinguishment of debt	**(10)**	(22)	
Discontinued operations		34	45
Gain on sale of minority interests in EG Holdings			21
Cumulative effect of change in accounting principle			(19)
Net income	**$ 3,956**	$ 5,234	$ 3,032

(a) Amounts relate to long-term 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.

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United States E&P income decreased $250 million, or 29 percent, in 2007 from 2006. This was the result of a $394 million decline in pretax income, while the effective income tax rate remained unchanged at 36 percent. The decrease in pretax income 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.

U.S. E&P income decreased $110 million in 2006 from 2005. This was the result of a $182 million decline in pretax income, partially offset by a slight reduction in the effective income tax rate from 37 percent in 2005 to 36 percent in 2006. The decrease in pretax income was due to increases in variable production costs, exploration expenses, property impairments and depreciation, depletion and amortization. Exploration expenses in 2006 were $51 million higher than in 2005, with half of the increase related to a Gulf of Mexico exploratory dry well. As discussed above, U.S. E&P revenues were flat from 2005 to 2006.

International E&P income decreased $24 million in 2007 from 2006, reflecting a decrease in pretax income of $79 million and an effective income tax rate of 62 percent in both years. The revenue decrease associated with lower liquid hydrocarbon sales volumes discussed above had the most significant impact on pretax income.

International E&P income increased $226 million, or 25 percent, in 2006 from 2005, reflecting an increase in pretax income of $1.639 billion and an increase in the effective tax rate from 34 percent in 2005 to 62 percent in 2006. The revenue increase discussed above, primarily related to higher liquid hydrocarbon realizations and higher liquid hydrocarbon sales volumes in Libya, had the most significant impact on pretax income. Depreciation, depletion and amortization and other variable costs increased with increased production to partially offset the revenue increase. Exploration expenses also increased $97 million in 2006 compared to 2005. Exploration expense related to dry wells and other write-offs was $68 million in 2006 and $44 million in 2005. Also included in 2006 exploration expense was $47 million for exiting the Cortland and Empire leases in Nova Scotia. The increase in the effective income tax rate was primarily the result of the income taxes related to our Libya operations, where the statutory income tax rate is in excess of 90 percent, and the 2006 increase in the U.K. supplemental corporation tax rate from 10 percent to 20 percent.

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 $39 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.

RM&T segment income increased $1.167 billion in 2006 from 2005, including the benefit from the 38 percent minority interest in MPC that we acquired on June 30, 2005. Pretax income increased $1.802 billion in 2006 from 2005. The pretax earnings reduction related to the minority interest was $376 million in 2005. The key driver of the increase in RM&T pretax income was our refining and wholesale marketing gross margin per gallon which averaged 22.88 cents in 2006 compared to 15.82 cents in 2005. The increase in the margin for 2006 reflected wider crack spreads, improved refined product sales realizations, the favorable effects of our ethanol blending program and increased refinery throughputs.

Included in the refining and wholesale marketing gross margins were pretax losses of $899 million in 2007, gains of $400 million in 2006 and losses of $238 million in 2005 related to commodity derivative instruments. For a more complete explanation of our strategies to manage market risk related to commodity prices, see Quantitative and Qualitative Disclosures about Market Risk.

We averaged 1.010 mmbpd of crude oil throughput in 2007, 980 mbpd in 2006 and 973 mbpd in 2005. Our reported crude oil refining capacity increased to 1.016 mmbpd in 2007 from 974 mbpd in 2006 due to overall

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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 each of the last three years.

RM&T OPERATING STATISTICS	2007	2006	2005
Refining and wholesale marketing gross margin *(dollars per gallon)*[(a)]	**$ 0.1848**	$ 0.2288	$ 0.1582
Refined product sales volumes *(thousands of barrels per day)*[(b)(c)]	**1,410**	1,425	1,455
Matching buy/sell volumes included in refined product sales volumes *(thousands of barrels per day)*[(c)]		24	77

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

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

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

IG segment income increased $116 million in 2007 from 2006 and decreased $39 million in 2006 from 2005. 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, partially offset by higher realized methanol prices. The provision for income taxes also increased $15 million in 2006.

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

Financial Condition

Net property, plant and equipment as of the end of the last two years is summarized in the following table.

(In millions)	2007	2006
E&P		
United States	**$ 4,248**	$ 3,636
International	**5,864**	4,879
Total E&P	**10,112**	8,515
OSM	**6,671**	
RM&T	**7,500**	6,452
IG	**31**	1,378
Corporate	**361**	308
Total	**$ 24,675**	$ 16,653

Net property, plant and equipment increased $8.022 billion in 2007 primarily due to the addition of the Oil Sands Mining assets recorded as a result of the Western acquisition. The decrease in integrated gas segment assets is due to the deconsolidation of EG Holdings discussed above.

Cash Flows

Net cash provided from operating activities totaled $6.521 billion in 2007, compared to $5.488 billion in 2006 and $4.738 billion in 2005. The $1.033 billion increase in 2007 primarily reflects working capital changes partially offset by lower net income. The $750 million increase in 2006 primarily reflects the impact of higher net income, partially offset by contributions of $635 million to our defined benefit pension plans and working capital changes.

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Net cash used in investing activities totaled $8.102 billion in 2007, compared with $2.955 billion in 2006 and $3.127 billion in 2005. 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)	**2007**	2006	2005
E&P			
United States	**$ 1,354**	$ 1,302	$ 638
International	**1,157**	867	728
Total E&P	**2,511**	2,169	1,366
OSM	**165**		
RM&T	**1,640**	916	841
IG	**93**	307	571
Corporate	**57**	41	18
Total	**$ 4,466**	$ 3,433	$ 2,796

The majority of the $1.033 billion increase in capital expenditures in 2007 over 2006 was in our RM&T segment and primarily related to the expansion of our Garyville, Louisiana refinery. Spending on E&P projects increased $342 million over 2006, primarily as a result of continued work on the Alvheim/Vilje development offshore Norway and exploration activities in Angola and the Gulf of Mexico. The decrease in integrated gas spending from 2006 reflects the completion of the LNG production facility in Equatorial Guinea in May 2007. The $637 million increase in capital expenditures in 2006 over 2005 primarily resulted from increased spending in the E&P segment and primarily related to significant acreage acquisitions in the Williston Basin of North Dakota and eastern Montana (the Bakken Shale formation) and the Piceance Basin of Colorado, as well as to the Alvheim/Vilje development and to the Neptune development in the Gulf of Mexico. The $264 million decrease in integrated gas spending from 2005 reflected the fact that the LNG production facility in Equatorial Guinea was nearing completion in 2006.

Acquisitions in 2007 consist primarily of the $3.907 billion cash portion of the Western acquisition purchase price, net of the $44 million of Western s cash acquired. In 2006, acquisitions primarily included cash payments of $718 million associated with our re-entry into Libya and in 2005 included cash payments of $506 million for the acquisition of Ashland s 38 percent ownership interest in MPC. See Note 6 to the consolidated financial statements.

Disposal of assets and of discontinued operations totaled $137 million, $966 million and $131 million in 2007, 2006 and 2005. Proceeds of $832 million from the disposal of discontinued operations in 2006 related to the sale of our Russian exploration and production businesses in June 2006. See Note 7 to the consolidated financial statements. 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.

Net cash provided from financing activities totaled $184 million in 2007, compared with cash used in financing activities of $2.581 billion in 2006 and $2.345 billion in 2005. 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 during both 2007 and 2006 were common stock repurchases under our share repurchase plan discussed below, dividend payments and debt repayments including the early extinguishment of portions of our outstanding debt. The most significant use of cash in 2005 was related to the repayment of $1.920 billion of debt assumed as a part of the acquisition of Ashland s 38 percent interest in MPC.

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 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, 2007, such reimbursements have totaled $280 million. The $1.0 billion obligation is reflected as long-term debt and the remaining $744 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, 2007.

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Derivative Instruments

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

Dividends to Stockholders

Dividends of $0.92 per common share or $637 million were paid during 2007. On January 27, 2008, our Board of Directors declared a dividend of $0.24 cents per share on our common stock, payable March 10, 2008, to stockholders of record at the close of business on February 20, 2008.

Liquidity and Capital Resources

Our main sources of liquidity and capital resources are internally generated cash flow from operations, committed credit facilities and access to both the debt and equity capital markets. Our ability to access the debt capital market is supported by our investment grade credit ratings. Our senior unsecured debt is currently rated investment grade by Standard and Poor s Corporation, Moody s Investor Services, Inc. and Fitch Ratings with ratings of BBB+, Baa1, and BBB+. These ratings were reaffirmed in July 2007 after the Western acquisition was announced. Because of the alternatives available to us, including internally generated cash flow and potential asset sales, we believe that our short-term and long-term liquidity is adequate to fund operations, including our capital spending programs, stock repurchase program, repayment of debt maturities and any amounts that ultimately may be paid in connection with contingencies.

We have a committed $3.0 billion revolving credit facility with third-party financial institutions terminating in May 2012. At December 31, 2007, there were no borrowings against this facility and we had no commercial paper outstanding under our U.S. commercial paper program that is backed by this revolving credit facility.

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

Our cash-adjusted debt-to-capital ratio (total debt-minus-cash to total debt-plus-equity-minus-cash) was 22 percent at December 31, 2007, compared to six percent at year-end 2006 as shown below. This includes $498 million of debt that is serviced by United States Steel.

(Dollars in millions)	**2007**	2006
Long-term debt due within one year	**$ 1,131**	$ 471
Long-term debt	**6,084**	3,061
Total debt	**$ 7,215**	$ 3,532
Cash	**$ 1,199**	$ 2,585
Trusteed funds from revenue bonds[(a)]	**$ 744**	$
Equity	**$ 19,223**	$ 14,607
Calculation:		
Total debt	**$ 7,215**	$ 3,532
Minus cash	**1,199**	2,585
Minus trusteed funds from revenue bonds	**744**	
Total debt minus cash	**5,272**	947
Total debt	**7,215**	3,532
Plus equity	**19,223**	14,607
Minus cash	**1,199**	2,585
Minus trusteed funds from revenue bonds	**744**	

Total debt plus equity minus cash	**$ 24,495**	$ 15,554
Cash-adjusted debt-to-capital ratio	**22%**	6%

(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, 2007.

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During 2007 and 2006, we extinguished portions of our outstanding debt with face values of $93 million and $162 million. The debt was repurchased at a weighted average price equal to 117 percent of face value in 2007 and 122 percent of face value in 2006. We will continue to evaluate debt repurchase opportunities as they arise.

A consolidated subsidiary, Marathon Oil Canada Corporation (formerly Western Oil Sands Inc.), had a committed 805 million Canadian dollar revolving term credit facility with third-party financial institutions at December 31, 2007. This facility was in place prior to our acquisition of Western, and had outstanding borrowings of 592 million Canadian dollars ($599 million) at December 31, 2007. Marathon Oil Canada Corporation did not meet certain financial covenants contained in the facility as of December 31, 2007. In February 2008, we repaid the outstanding balance and terminated the facility.

As discussed in more detail below under Outlook, we have approved a capital, investment and exploration budget of $7.993 billion for 2008, which represents a 67 percent increase over our 2007 spending. Consistent with our philosophy of maintaining financial discipline and flexibility, we have commenced a review of our portfolio of assets with the intent of monetizing those assets which are either mature or otherwise non-strategic, thus allowing us to re-deploy our capital into the projects included in our capital, investment and exploration budget. We are in the early stage of this review process, so we expect that the majority of proceeds from any such asset sales would be received in the second half of 2008.

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.

Share Repurchase Program

Since January 2006, our Board of Directors has authorized a common share repurchase program totaling $5 billion. As of December 31, 2007, we had repurchased 58 million common shares at a cost of $2.520 billion. 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; however, we expect to complete the authorized purchases by the end of 2009, although repurchases are likely to be less ratable than in prior years. 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.

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, 2007.

Summary of Contractual Cash Obligations

(In millions)	Total	2008	2009-2010	2011-2012	Later Years
Long-term debt (excludes interest)[a][b]	$ 6,947	$ 1,067	$ 136	$ 1,664	$ 4,080
Sale-leaseback financing[a]	308	11	41	55	201
Capital lease obligations[a]	193	68	37	35	53
Operating lease obligations[a]	1,063	165	267	183	448
Operating lease obligations under sublease[a]	26	5	10	11	
Purchase obligations:					
Crude oil, feedstock, refined product and ethanol contracts[c]	18,434	16,713	604	593	524
Transportation and related contracts	1,944	438	279	271	956
Contracts to acquire property, plant and equipment	3,893	2,025	1,798	33	37
LNG terminal operating costs[d]	166	13	25	25	103
Service and materials contracts[e]	1,622	386	464	253	519
Unconditional purchase obligations[f]	59	7	15	15	22
Commitments for oil and gas exploration (non-capital)[g]	83	76	2	4	1
Total purchase obligations	26,201	19,658	3,187	1,194	2,162
Other long-term liabilities reported in the consolidated balance sheet[h]	1,970	110	362	241	1,257
Total contractual cash obligations[i]	**$ 36,708**	**$ 21,084**	**$ 4,040**	**$ 3,383**	**$ 8,201**

(a) Upon the Separation, United States Steel assumed certain debt and lease obligations. Such amounts are included in the above table because we remain primarily liable.

(b) We anticipate cash payments for interest of $425 million for 2008, $838 million for 2009-2010, $740 million for 2011-2012 and $3.700 billion for the remaining years for a total of $5.703 billion.

(c) The majority of these contractual obligations as of December 31, 2007 relate to contracts to be satisfied within the first 180 days of 2008. These contracts include variable price arrangements and some contracts are accounted for as nontraditional derivatives.

(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 is 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 2016.

(i) Includes $544 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 Summary of Contractual Cash Obligations Assumed by United States Steel.

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 generally accepted accounting principles. Although off-balance sheet arrangements serve a variety of our business purposes, we are not dependent on these arrangements to maintain our liquidity and capital resources, and we are not aware of any circumstances that are reasonably likely to cause the off-balance sheet arrangements to have a material adverse effect on liquidity and capital resources.

We have provided various guarantees related to equity method investees, United States Steel and others. These arrangements are described in Note 28 to the consolidated financial statements.

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We are a party to an agreement that would require us to purchase, under certain circumstances, the interest in Pilot Travel Centers LLC (PTC) not currently owned. This put/call agreement is described in Note 28 to the consolidated financial statements.

Nonrecourse Indebtedness of Investees

Certain of our investees have incurred indebtedness that we do not support through guarantees or otherwise. If we were obligated to share in this debt on a pro rata ownership basis, our share would have been $522 million as of December 31, 2007. Of this amount, $251 million relates to PTC. If any of these investees default, we have no obligation to support the debt. Our partner in PTC has guaranteed $50 million of the total PTC debt.

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 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, 2007, 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 2009 through 2033. Accrued interest payable on these bonds was $9 million at December 31, 2007.

- $45 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, 2007.

- $38 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, 2007.

- $26 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 of all obligations of United States Steel as general partner of Clairton 1314B Partnership, L.P. to the limited partners. United States Steel has reported that it currently has no unpaid outstanding obligations to the limited partners. See Note 3 to the consolidated financial statements.

Of the total $533 million, obligations of $507 million and corresponding receivables from United States Steel were recorded on our consolidated balance sheet as of December 31, 2007 (current portion $22 million; long-term portion $485 million). The remaining $26 million was related to off-balance sheet arrangements and contingent liabilities of United States Steel.

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The table below provides aggregated information on the portion of our consolidated obligations to make future cash payments under existing contracts that have been assumed by United States Steel as of December 31, 2007.

Summary of Contractual Cash Obligations Assumed by United States Steel

(In millions)	**Total**	**2008**	**2009-2010**	**2011-2012**	**Later Years**
Long-term debt (excludes interest)[a]	$ 415	$	$	$	$ 415
Sale-leaseback financing (includes imputed interest)	55	11	22	22	
Capital lease obligations	48	10	19	19	
Operating lease obligations under sublease	26	5	10	11	
Total contractual cash obligations assumed by United States Steel	$ 544	$ 26	$ 51	$ 52	$ 415

(a) We anticipate cash payments for interest of $23 million for 2008, $46 million for 2009-2010, $38 million for 2011-2012 and $223 million for the later years to be assumed by United States Steel.

United States Steel reported in its Form 10-K for the year ended December 31, 2007, that it has restrictive covenants related to its indebtedness that could have an adverse effect on its financial position and liquidity. Further, United States Steel reported that the restrictive nature of its financial covenants decreased during 2007 and that its management believes that its liquidity will be adequate to satisfy its obligations for the foreseeable future.

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 marketed 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 to our 50 percent equity method investee, PTC, which consist primarily of refined petroleum products, accounted for 2.5 percent or less of our total sales revenue for 2007, 2006 and 2005. PTC is the largest travel center network in the United States and operates 286 travel centers in the United States and Canada. Prior to our acquisition of Ashland s 38 percent interest in MPC on June 30, 2005, Ashland was a related party as a result of that interest. During that time, we sold refined petroleum products consisting mainly of petrochemicals, base lube oils and asphalt to Ashland. Our sales to Ashland accounted for less than one percent of our total sales revenue for 2005. We believe that these transactions were conducted under terms comparable to those with unrelated parties.

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

We have incurred and will continue to incur substantial capital, operating and maintenance, and remediation expenditures as a result of environmental laws and regulations. If these expenditures, as with all costs, are not ultimately reflected in the prices of our products and services, our operating results will be adversely affected. We believe that substantially all of our competitors must comply with similar environmental laws and regulations. However, the specific impact on each competitor may vary depending on a number of factors, including the age and location of its operating facilities, marketing areas, 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)	**2007**	2006	2005
Capital	**$ 199**	$ 176	$ 390
Compliance			

Operating and maintenance	**287**	309	250
Remediation[b]	**25**	20	25
Total	**$ 511**	$ 505	$ 665

(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.

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Our environmental capital expenditures accounted for four percent of capital expenditures for continuing operations in 2007, five percent in 2006 and 14 percent in 2005.

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 approximately $313 million or 4 percent of capital expenditures in 2008. Predictions beyond 2008 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 $735 million in 2009; 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 Business   Environmental Matters and for information on legal proceedings related to environmental matters, see Legal Proceedings.

Outlook

Capital, Investment and Exploration Budget

Our Board of Directors approved a capital, investment and exploration budget of $7.993 billion for 2008, which includes budgeted capital expenditures of $7.651 billion. This represents a 67 percent increase over 2007 spending. The focus of the 2008 budget is to grow our refining capacity through the Garyville refinery expansion, further develop our long-life Canadian oil sands assets, capitalize on the ownership of those oil sands assets by upgrading and expanding our Detroit refinery, fund our ongoing exploration activities and develop existing fields, including new developments in Angola and the Gulf of Mexico. The budget includes worldwide production spending of $2.144 billion, primarily in the United States for expansion of the Bakken shale and Piceance Basin resource plays and development of the Droshky prospect in the Gulf of Mexico, but also in Norway and Angola. The worldwide exploration budget of $1.045 billion includes plans to drill six to ten exploration or appraisal wells. It also includes $150 million related to our high bids on leases from the October 2007 Gulf of Mexico lease sale which were awarded in early 2008. Other exploration plans include activity within or adjacent to our onshore producing properties in the United States, appraisal drilling and pre-FEED costs in Angola, and evaluation drilling and feasibility studies of the in-situ recovery projects in Canada. The budget includes $910 million for the Oil Sands Mining segment, primarily for the Phase 1 expansion of the AOSP 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 associated infrastructure. The budget includes $3.528 billion for RM&T, primarily for the Garyville refinery expansion and the Detroit refinery heavy oil upgrading and expansion project. The RM&T budget also includes increased investments in transportation, logistics and marketing assets. The Integrated Gas segment budget of $20 million is substantially lower than 2007 because construction on the LNG production facility in Equatorial Guinea was completed and the facility began operations in 2007. The remaining $346 million is designated for capitalized interest and corporate activities.

This capital, investment and exploration budget represents a significant increase over our 2007 spending. Consistent with our philosophy of maintaining financial discipline and flexibility, we have commenced a review of our portfolio of assets with the intent of monetizing those assets which are either mature or otherwise non-strategic, thus allowing us to re-deploy our capital into the projects included in our capital, investment and exploration budget. We are in the early stage of this review process, so we expect that the majority of proceeds from any such asset sales would be received in the second half of 2008.

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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. The discussion above also contains forward-looking statements regarding a review of our portfolio of assets. 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.

Exploration and Production

We announced nine discoveries in 2007 (eight in deepwater Angola and one in the Gulf of Mexico). Major exploration activities, which are currently underway or under evaluation, include those:

- offshore Angola, on Block 31 in which we hold a 10 percent outside-operated interest and have announced 15 discoveries, and on Block 32, in which we hold a 30 percent outside-operated interest and have announced 11 discoveries. We plan to participate in four to five exploration or appraisal wells in these deepwater blocks in 2008. Current plans call for a potential development area in the northeastern part of Block 31, which encompasses the Plutao, Saturno, Venus and Marte discoveries. Additional potential development areas lie in the southeast and middle portions of the block. Seven of the Block 32 discoveries form our first potential development in the eastern area of that block.

- in Equatorial Guinea, where 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;

- in Norway, where we now own interests in 16 licenses covering over 800,000 gross acres offshore and plan to drill one or two exploration wells during 2008;

- in the United Kingdom, where we plan to participate in the U.K. Onshore Licensing Round during 2008 to secure additional coal bed methane acreage; and

- in the Gulf of Mexico, where we plan to participate in two to three exploration wells during 2008.

During 2007, we continued to make progress in advancing key development projects that will help serve as the basis for our production growth profile in the coming years. Major development and production activities currently underway or under evaluation include those:

- in the Gulf of Mexico, with the Neptune development and the Droshky discovery. The Neptune development, in which we own a 30 percent outside-operated working interest, is on target for first production by early 2008. Development of the Droshky discovery, in which we own a 100 percent working interest, is expected to be sanctioned during 2008, with first production as early as 2010 dependent upon delivery of key equipment and regulatory approvals. Rig capacity has been secured for Droshky development drilling.

- in Norway, where our Alvheim/Vilje development will consist of an FPSO vessel with subsea infrastructure. The FPSO sailed from the shipyard in mid-February 2008 to undergo testing, after which it will proceed offshore for connection to the subsea infrastructure.

First production is expected at the end of the first quarter of 2008, weather permitting, at which time six wells will be available. Drilling activities will continue in 2008. A peak net production rate of 75 mboepd is expected in 2008. We are the operator of the Alvheim development, which includes 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. We own a 47 percent outside-operated interest in the nearby Vilje discovery. Also, the Volund discovery, a tie-back to the Alvheim FPSO continues to make progress towards first production in 2009. We own a 65 percent interest in Volund and serve as operator;

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- in Libya, where we continue to work with our partners to maximize the potential of this major asset. We own a 16.33 percent outside-operated interest in the approximately 13 million acre Waha concessions;

- in Ireland, where the Corrib natural gas development project continues and the operator expects first production in 2009. We own a 19 percent outside-operated interest in Corrib;

- in the Piceance Basin of Colorado, where we have two drilling rigs running, and plan to increase the rig count to four by the end of 2008, drilling 165 wells in the region over the next two years; and

- in the Williston Basin of North Dakota and eastern Montana (the Bakken shale formation), where we have six rigs running and plan to drill approximately 350 locations over the next four to five years.

With the Alvheim/Vilje and Neptune developments coming online, we estimate that our 2008 liquid hydrocarbon and natural gas sales will average approximately 380 to 420 mboepd, excluding the impact of acquisitions and dispositions. Projected liquid hydrocarbon and natural gas sales are based on a number of assumptions, including (among others) pricing, supply and demand for petroleum products, the amount of capital available for exploration and development, regulatory constraints, timing of commencing production from new wells, drilling rig availability, inability or delay in obtaining necessary government and third-party approvals and permits, unforeseen hazards such as weather conditions, acts of war or terrorist acts and the government or military response, and other geological, operating and economic considerations. These assumptions may prove to be inaccurate.

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.

Oil Sands Mining

The AOSP s Phase 1 expansion is under construction and we expect that it will be complete in late 2010. 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 Scotford upgrader returned to full operation in December 2007 after a mid-November fire and the completion of maintenance that had originally been scheduled for the first quarter of 2008 and was completed in conjunction with the necessary repairs. We anticipate our net bitumen production will be approximately 30 mbpd in 2008. Projected bitumen production is based upon a number of assumptions, including pricing, supply and demand for petroleum products, regulatory constraints, unforeseen hazards such as weather conditions, acts of war or terrorist acts and government or military response thereto, and other geological, operating and economic considerations.

The above discussion includes forward-looking statements with respect to the 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.

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Refining, Marketing and Transportation

Throughout 2007, we remained focused on our strategy of leveraging refining and marketing investments in core markets, as well as expanding and enhancing our asset base while controlling costs. Our 2007 average daily crude oil throughput and total refinery throughput were at record levels.

Construction continues on an expansion of our Garyville, Louisiana refinery with a total projected cost of $3.2 billion (excluding capitalized interest). This expansion will increase the refinery s crude oil throughput capacity by 180 mbpd and, when completed in late 2009, will enable the refinery to provide an additional 7.5 million gallons of clean transportation fuels to the market each day.

In 2007, a heavy oil upgrading and expansion project at our Detroit, Michigan refinery was approved at a total projected cost of $1.9 billion (excluding capitalized interest). Construction is expected to begin in the first half of 2008, subject to obtaining the necessary permits from applicable regulatory agencies.

We also continue our investment in transportation and storage assets to increase our ability to blend and distribute ethanol. By mid-2008, we expect to have the capacity to blend to an E-10 level (90 percent gasoline and 10 percent ethanol) across our entire gasoline distribution network.

We previously estimated that we would spend approximately $400 million over a four-year period beginning in 2008 to comply with Mobile Source Air Toxics II regulations relating to benzene. We have not finalized our strategy or cost estimates to comply with these recently promulgated requirements, but the cost estimates will increase and may be approximately $1 billion over a three-year period beginning in 2008. The cost estimates have increased due to better definition of the projects needed to meet the requirements of the finalized regulations and updated construction cost estimates.

The above discussion includes forward-looking statements concerning the planned expansion of the Garyville refinery, the Detroit refinery heavy oil upgrading and expansion project, our ethanol program and Mobile Source Air Toxics II regulations compliance costs. Some factors that could affect the Garyville and Detroit projects include necessary government and third-party approvals, transportation logistics, availability of materials and labor, unforeseen hazards such as weather conditions, other risks customarily associated with construction projects and crude oil supply. Factors that could affect our ethanol program include necessary government and third-party approvals, availability of materials and labor, unforeseen hazards such as weather conditions and other risks customarily associated with construction projects. The compliance cost estimates are subject to change as FEED work is completed in 2008. These factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Integrated Gas

Net worldwide LNG sales volumes are expected to average 6,225 to 6,875 metric tonnes per day in 2008. 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.

In 2007 we completed those portions of the FEED required to support the near-term efforts related to a potential second LNG production facility on Bioko Island, Equatorial Guinea. The scope of the FEED work for the potential 4.4 mmtpa LNG project included feed gas metering, liquefaction, refrigeration, ethylene storage, boil-off gas compression, product transfer to storage and LNG product metering. We expect to make progress towards an investment decision in 2008.

The above discussion contains forward looking statements with respect to the possible expansion of the LNG production facility which could potentially be affected by partner approvals, access to sufficient natural gas volumes through exploration or commercial negotiations with other resource owners and access to sufficient re-gasification capacity. 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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Accounting Standards Not Yet Adopted

In December 2007, the FASB issued SFAS No. 141 (Revised 2007), Business Combinations. This statement significantly changes the accounting for business combinations. Under SFAS No. 141(R), an acquiring entity will be required to recognize all the assets acquired, liabilities assumed and any noncontrolling interest in the acquiree at their acquisition-date fair values 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. Additional disclosures are also required. For us, SFAS No. 141(R) will be applied prospectively effective January 1, 2009.

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. For us, SFAS No. 160 will be 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 are currently evaluating the provisions of this statement.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities. This statement permits entities to choose to measure many financial instruments and certain other items at fair value 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. For us, SFAS No. 159 is effective January 1, 2008, and retrospective application is not permitted. We did not elect the fair value option when this standard became effective.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 does not require any new fair value measurements but may require some entities to change their measurement practices. In February 2008, the FASB issued FASB Staff Position (FSP) FAS 157-1, Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13, which removes certain leasing transactions from the scope of SFAS No. 157, and FSP FAS 157-2, Effective Date of FASB Statement No. 157, which defers the effective date of SFAS No. 157 for one year for certain nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis. For us, except for the nonfinancial assets and liabilities subject to the one-year deferral, SFAS No. 157 is effective January 1, 2008. We do not expect adoption of this statement to have a significant effect 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.

Certain long-term natural gas contracts in the United Kingdom that are accounted for as derivative instruments are excluded from E&P segment income. For additional information on these U.K. natural gas contracts, see Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Estimates Fair Value Estimates.

Our OSM segment uses 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.

Our RM&T segment uses commodity derivative instruments on a selective basis, primarily 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 or during the time that crude oil inventories are held before they are actually refined into salable petroleum products. To a lesser extent, 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. Our strategies allow us to realize acceptable margins for our various refined products but at times may limit our ability to take advantage of certain market opportunities.

Additionally, certain contracts in our RM&T segment involving the purchase or sale of commodities are not considered normal purchases or normal sales under generally accepted accounting principles and are required to be accounted for as derivative instruments.

Generally, commodity derivative instruments used in our E&P segment qualify for hedge accounting. As a result, we do not recognize in net income any changes in the fair value of those derivative instruments until the underlying physical transaction occurs. We have not attempted to qualify 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 Derivative Positions as of December 31, 2007 and Sensitivity Analysis

At year end 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

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normal levels of activity. At December 31, 2007, we had no open derivative contracts related to our future sales of liquid hydrocarbons and natural gas and therefore remained substantially exposed to market prices of these commodities.

At October 18, 2007, Western held crude oil put options purchased in October 2005 for the three-year period beginning January 1, 2007. 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, 2007, the following put and call options were outstanding:

	Option Expiration Dates	
	2008	2009
Option Contract Volumes *(Barrels Per Day)***:**		
Put Options Purchased	20,000	20,000
Call Options Sold	15,000	15,000
Average Exercise Price *(Dollars Per Barrel)***:**		
Put Options	$ 54.25	$ 50.50
Call Options	$ 94.25	$ 90.50

At year end our RM&T segment held open derivative contracts in amounts that were in line with normal levels of activity.

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, 2007, 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	$ 1(c)	$
Natural gas	99(c)	220(c)
Refined products	22(c)	59(c)

(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, 2007. Included in the natural gas impacts above are $102 million and $229 million for hypothetical price changes of 10 percent and 25 percent related to the long-term U.K. natural gas contracts accounted for as derivative instruments. We evaluate our portfolio of commodity derivative instruments on an ongoing basis and add or revise strategies in anticipation of changes in market conditions and in risk profiles. We are also exposed to credit risk in the event of nonperformance by counterparties. The creditworthiness of counterparties is reviewed continuously and master netting agreements are used when practical. Changes to the portfolio after December 31, 2007, 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 2007, from a low of 15 contracts on April 30, 2007, to a high of 1,475 contracts on March 15, 2007, and averaged 719 for the year. The number of net open contracts for the RM&T segment varied throughout 2007, from a low of 22 contracts on February 7, 2007, to a high of 31,872 contracts on September 24, 2007, and averaged 12,261 for the year. The number of net open contracts for the OSM segment varied throughout 2007, from a low of 25,585 contracts on December 31, 2007 to a high of 28,345 contracts on October 18, 2007, the Western acquisition date, and averaged 26,965 for the post-acquisition period. 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.

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Derivative Gains or Losses Included in Results of Operations

Pretax derivative losses of $15 million in 2007 and gains of $25 million in 2006 and $7 million in 2005 were included in E&P segment income and were primarily related to derivatives utilized to protect the value of natural gas in storage and margins on natural gas purchased for use in our marketing activities.

Pretax derivative losses of $54 million were included in OSM segment income for 2007. These losses primarily resulted from the increase in crude oil prices since the acquisition date of Western.

Pretax derivative gains and losses included in RM&T segment income for each of the last three years are summarized in the following table:

(In millions)	**2007**	2006	2005
Strategy:			
Mitigate price risk on purchases of crude oil and other commodities	**$ (378)**	$ 204	$ (57)
Mitigate price risk on carrying values of inventories	**(511)**	200	(118)
Other	**(10)**	(4)	(63)
Subtotal, non-trading activities	**(899)**	400	(238)
Trading activities	**(1)**	1	(87)
Total net derivative gains (losses)	**$ (900)**	$ 401	$ (325)

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. We have entered into several interest rate swap agreements, designated as fair value hedges, which effectively resulted in an exchange of existing obligations to pay fixed interest rates for obligations to pay floating rates. The following table summarizes our interest rate swaps as of December 31, 2007.

(In millions)	**Fixed Rate to be Received**	**Notional Amount**	**Swap Maturity**	**Fair Value**
Floating Rate to be Paid:				
Six-Month LIBOR +3.285%	6.850%	$ 400	2008	$ (2)
Six-Month LIBOR +2.142%	6.125%	$ 200	2012	$ (1)

Sensitivity analysis of the projected incremental effect of a hypothetical 10 percent change in interest rates is provided in the following table.

	December 31, 2007	
(In millions)	**Fair Value**(b)	**Incremental Change in Fair Value**
Financial assets (liabilities):(a)		
Receivables from United States Steel	$ 500 (c)	$ 10(d)
Interest rate swap agreements	$ (3)(c)	$ 5(d)

Long-term debt, including amounts due within one year	$ (7,176)[c]	$ (330)[d]

(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) See Notes 18 and 19 to the consolidated financial statements for the carrying value of these instruments.

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

(d) 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 long-term debt at December 31, 2007. For interest rate swap agreements, this assumes a 10 percent decrease in the effective swap rate at December 31, 2007.

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At December 31, 2007, our portfolio of long-term debt was substantially comprised of fixed rate instruments. Therefore, the fair value of the portfolio is relatively sensitive to interest rate fluctuations. Our sensitivity to interest rate declines and corresponding increases in the fair value of our debt portfolio unfavorably affects our results of operations and cash flows only when we elect to repurchase or otherwise retire fixed-rate debt at prices above carrying value.

Foreign Currency Exchange Rate Risk

We manage our exposure to foreign currency exchange rates by utilizing forward and option contracts. The primary objective of this program is to reduce our exposure to movements in foreign currency exchange rates by locking in such rates. The following table summarizes our derivative foreign currency instruments as of December 31, 2007.

(Dollars in millions)	**Period**	**Notional Amount**	**Average Forward Rate**[(a)]	**Fair Value**[(b)]
Foreign Currency Forwards:				
Euro	January 2008 November 2008	$ 31	1.281(c)	$ 4
Kroner (Norway)	January 2008 October 2009	$ 71	6.090(d)	$ 8
Dollar (Canada)	February 2008	$ 54	1.007(d)	

(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 forward contracts of a hypothetical 10 percent change to exchange rates at December 31, 2007, would be approximately $11 million.

During 2007, we entered into derivative foreign currency instruments with a notional amount of $3.5 billion to limit our exposure to changes in the Canadian dollar exchange rate related to the cash portion of the purchase for Western. These derivative instruments were settled on October 17, 2007, and a pretax gain of $182 million was recognized.

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.

Clarence P. Cazalot, Jr.	Janet F. Clark	Michael K. Stewart
President and	*Executive Vice President*	*Vice President, Accounting*
Chief Executive Officer	*and Chief Financial Officer*	*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, 2007. This evaluation did not include the internal control over financial reporting at Marathon Oil Canada Corporation (formerly, Western Oil Sands Inc.) which was acquired in a purchase business combination on October 18, 2007. Marathon Oil Canada Corporation s loss before income taxes and total assets represent $100 million and $8.9 billion, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2007.

The effectiveness of Marathon s internal control over financial reporting as of December 31, 2007 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Clarence P. Cazalot, Jr.
President and
Chief Executive Officer

Janet F. Clark
Executive Vice President
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, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 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, 2007, 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 methods of accounting for purchases and sales of inventory with the same counterparty and defined benefit pension and other postretirement plans in 2006, and its method of accounting for conditional asset retirement obligations in 2005.

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.

As described in Management s Report on Internal Control over Financial Reporting, management has excluded Marathon Oil Canada Corporation from its assessment of internal control over financial reporting as of December 31, 2007 because it was acquired by the Company in a purchase business combination on October 18, 2007. We have also excluded Marathon Oil Canada Corporation from our audit of internal control over financial reporting. Marathon Oil Canada Corporation is a wholly-owned subsidiary whose loss before income taxes and total assets represent $100 million and $8.9 billion, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2007.

PricewaterhouseCoopers LLP

Houston, Texas

February 28, 2008

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Consolidated Statements of Income

(Dollars in millions, except per share data)	**2007**	2006	2005
Revenues and other income:			
Sales and other operating revenues (including consumer excise taxes)	**$ 62,800**	$ 57,973	$ 48,948
Revenues from matching buy/sell transactions	**127**	5,457	12,636
Sales to related parties	**1,625**	1,466	1,402
Income from equity method investments	**545**	391	265
Net gain on disposal of assets	**36**	77	57
Other income	**74**	85	37
Total revenues and other income	**65,207**	65,449	63,345
Costs and expenses:			
Cost of revenues (excludes items below)	**49,104**	42,415	37,806
Purchases related to matching buy/sell transactions	**149**	5,396	12,364
Purchases from related parties	**363**	210	225
Consumer excise taxes	**5,163**	4,979	4,715
Depreciation, depletion and amortization	**1,613**	1,518	1,303
Selling, general and administrative expenses	**1,327**	1,228	1,155
Other taxes	**394**	371	318
Exploration expenses	**454**	365	217
Total costs and expenses	**58,567**	56,482	58,103
Income from operations	**6,640**	8,967	5,242
Net interest and other financial income (costs)	**41**	37	(146)
Gain on foreign currency derivative instruments	**182**		
Loss on early extinguishment of debt	**(17)**	(35)	
Minority interests in loss (income) of:			
Marathon Petroleum Company LLC			(384)
Equatorial Guinea LNG Holdings Limited	**3**	10	8
Income from continuing operations before income taxes	**6,849**	8,979	4,720
Provision for income taxes	**2,901**	4,022	1,714
Income from continuing operations	**3,948**	4,957	3,006
Discontinued operations	**8**	277	45
Income before cumulative effect of change in accounting principle	**3,956**	5,234	3,051
Cumulative effect of change in accounting principle			(19)
Net income	**$ 3,956**	$ 5,234	$ 3,032
Per Share Data			
Basic:			
Income from continuing operations	**$ 5.72**	$ 6.92	$ 4.22

Net income	**$ 5.73**	$ 7.31	$ 4.26
Diluted:			
Income from continuing operations	**$ 5.68**	$ 6.87	$ 4.19
Net income	**$ 5.69**	$ 7.25	$ 4.22

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

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Consolidated Balance Sheets

(Dollars in millions, except per share data) December 31	**2007**	2006
Assets		
Current assets:		
Cash and cash equivalents	**$ 1,199**	$ 2,585
Receivables, less allowance for doubtful accounts of $3 and $3	**5,818**	4,114
Receivables from United States Steel	**22**	32
Receivables from related parties	**79**	63
Inventories	**3,277**	3,173
Other current assets	**192**	129
Total current assets	**10,587**	10,096
Equity method investments	**2,630**	1,539
Receivables from United States Steel	**485**	498
Property, plant and equipment, net	**24,675**	16,653
Goodwill	**2,899**	1,398
Intangible assets, net	**288**	180
Other noncurrent assets	**1,182**	467
Total assets	**$ 42,746**	$ 30,831
Liabilities		
Current liabilities:		
Accounts payable	**$ 8,281**	$ 5,586
Payable to United States Steel		13
Payables to related parties	**44**	264
Payroll and benefits payable	**417**	409
Accrued taxes	**712**	598
Deferred income taxes	**547**	631
Accrued interest	**128**	89
Long-term debt due within one year	**1,131**	471
Total current liabilities	**11,260**	8,061
Long-term debt	**6,084**	3,061
Deferred income taxes	**3,389**	1,897
Defined benefit postretirement plan obligations	**1,092**	1,245
Asset retirement obligations	**1,131**	1,044
Payable to United States Steel	**5**	7
Deferred credits and other liabilities	**562**	391
Total liabilities	**23,523**	15,706
Minority interests in Equatorial Guinea LNG Holdings Limited		518
Commitments and contingencies		
Stockholders Equity		
Preferred stock issued and outstanding 5 million and no shares (no par value, 6 million shares authorized)		
Common stock:		
Issued 765 million and 736 million shares (par value $1 per share, 1.1 billion shares authorized)	**765**	736
Securities exchangeable into common stock issued and outstanding 5 million and no shares (no par value, unlimited shares authorized)		
Held in treasury, at cost 55 million and 40 million shares	**(2,384)**	(1,638)

Additional paid-in capital	**6,679**	4,784
Retained earnings	**14,412**	11,093
Accumulated other comprehensive loss	**(249)**	(368)
Total stockholders equity	**19,223**	14,607
Total liabilities and stockholders equity	**$ 42,746**	$ 30,831

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

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Consolidated Statements of Cash Flows

(Dollars in millions)	**2007**	2006	2005
Increase (decrease) in cash and cash equivalents			
Operating activities			
Net income	**$ 3,956**	$ 5,234	$ 3,032
Adjustments to reconcile net income to net cash provided from operating activities:			
Loss on early extinguishment of debt	**17**	35	
Cumulative effect of change in accounting principle			19
Income from discontinued operations	**(8)**	(277)	(45)
Deferred income taxes	**(347)**	268	(205)
Minority interests in income (loss) of subsidiaries	**(3)**	(10)	376
Depreciation, depletion and amortization	**1,613**	1,518	1,303
Pension and other postretirement benefits, net	**32**	(404)	71
Exploratory dry well costs and unproved property impairments	**233**	166	111
Net gain on disposal of assets	**(36)**	(77)	(57)
Equity method investments, net	**(43)**	(200)	(65)
Changes in the fair value of long-term U.K. natural gas contracts	**232**	(454)	386
Changes in:			
Current receivables	**(1,361)**	(535)	(1,164)
Inventories	**(90)**	(133)	(150)
Current accounts payable and accrued expenses	**2,351**	237	1,065
All other, net	**(25)**	50	(22)
Net cash provided from continuing operations	**6,521**	5,418	4,655
Net cash provided from discontinued operations		70	83
Net cash provided from operating activities	**6,521**	5,488	4,738
Investing activities			
Capital expenditures	**(4,466)**	(3,433)	(2,796)
Acquisitions, net of cash acquired	**(3,926)**	(741)	(506)
Disposal of assets	**137**	134	131
Disposal of discontinued operations		832	
Proceeds from sale of minority interests in Equatorial Guinea LNG Holdings Limited			163
Trusteed funds withdrawals	**280**		
Restricted cash deposits	**(44)**	(19)	(54)
withdrawals	**9**	43	41
Investments loans and advances	**(114)**	(17)	(28)
repayments of loans and return of capital	**59**	298	15
Deconsolidation of Equatorial Guinea LNG Holdings Limited	**(37)**		
Investing activities of discontinued operations		(45)	(94)
All other, net		(7)	1
Net cash used in investing activities	**(8,102)**	(2,955)	(3,127)
Financing activities			
Commercial paper and other revolving credit arrangements net	**90**		
Borrowings	**2,071**		
Debt issuance costs	**(20)**		
Payment of debt assumed in acquisition			(1,920)

Other debt repayments	**(594)**	(501)	(8)
Issuance of common stock	**27**	50	78
Purchases of common stock	**(822)**	(1,698)	
Excess tax benefits from stock-based compensation arrangements	**30**	35	
Dividends paid	**(637)**	(547)	(436)
Contributions from minority shareholders of Equatorial Guinea LNG Holdings Limited	**39**	80	213
Distributions to minority shareholder of Marathon Petroleum Company LLC			(272)
Net cash provided from (used in) financing activities	**184**	(2,581)	(2,345)
Effect of exchange rate changes on cash	**11**	16	(18)
Net decrease in cash and cash equivalents	**(1,386)**	(32)	(752)
Cash and cash equivalents at beginning of year	**2,585**	2,617	3,369
Cash and cash equivalents at end of year	**$ 1,199**	$ 2,585	$ 2,617

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

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Consolidated Statements of Stockholders Equity

	Stockholders Equity			Shares		
(In millions, except per share data)	**2007**	2006	2005	**2007**	2006	2005
Preferred stock issued						
Balance at beginning of year	**$**	$	$			
Issuances				**5**		
Balance at end of year	**$**	$	$	**5**		
Common stock						
Issued						
Balance at beginning of year	**$ 736**	$ 734	$ 694	**736**	734	693
Issuances	**29**	2	40	**29**	2	41
Balance at end of year	**$ 765**	$ 736	$ 734	**765**	736	734
Securities exchangeable for common stock						
Balance at beginning of year	**$**	$	$			
Issuances				**5**		
Balance at end of year	**$**	$	$	**5**		
Held in treasury						
Balance at beginning of year	**$ (1,638)**	$ (8)	$ (1)	**(40)**		
Repurchases	**(845)**	(1,712)	(7)	**(17)**	(42)	
Reissuances for employee stock plans	**99**	82		**2**	2	
Balance at end of year	**$ (2,384)**	$ (1,638)	$ (8)	**(55)**	(40)	
				Comprehensive Income		
				2007	2006	2005
Additional paid-in capital						
Balance at beginning of year	**$ 4,784**	$ 4,744	$ 3,681			
Stock issuances	**1,844**	(8)	1,028			
Stock-based compensation	**51**	48	35			
Balance at end of year	**$ 6,679**	$ 4,784	$ 4,744			
Unearned compensation						
Balance at beginning of year	**$**	$ (20)	$ (9)			
Change in accounting principle		20				
Changes during year			(11)			
Balance at end of year	**$**	$	$ (20)			
Retained earnings						
Balance at beginning of year	**$ 11,093**	$ 6,406	$ 3,810			
Net income	**3,956**	5,234	3,032	**$ 3,956**	$ 5,234	$ 3,032
Dividends paid (per share: $0.92 in 2007, $0.76 in 2006 and $0.60 in 2005)	**(637)**	(547)	(436)			
Balance at end of year	**$ 14,412**	$ 11,093	$ 6,406			
Accumulated other comprehensive loss						
Minimum pension liability adjustments						
Balance at beginning of year	**$**	$ (141)	$ (71)			
Changes during year, net of tax of $, $74 and $42		114	(70)		114	(70)

Reclassification to defined benefit postretirement plans		27				
Balance at end of year	**$**	$	$ (141)			
Defined benefit postretirement plans						
Balance at beginning of year	**$ (375)**	$	$			
Actuarial gains, net of tax of $87	**110**			**110**		
Prior service costs, net of tax of $1	**2**			**2**		
Reclassification from minimum pension liability adjustments		(27)				
Change in accounting principle, net of tax of $289		(348)				
Balance at end of year	**$ (263)**	$ (375)	$			
Other						
Balance at beginning of year	**$ 7**	$ (10)	$ 7			
Changes during year, net of tax of $4, $9 and $3	**7**	17	(17)	**7**	12	(17)
Balance at end of year	**$ 14**	$ 7	$ (10)			
Total at end of year	**$ (249)**	$ (368)	$ (151)			
Comprehensive income				**$ 4,075**	$ 5,360	$ 2,945
Total stockholders equity	**$ 19,223**	$ 14,607	$ 11,705			

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

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Notes to Consolidated Financial Statements

1. Summary of Principal Accounting Policies

Marathon Oil Corporation (Marathon or the Company) is 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, and development of other projects to link stranded natural gas resources with key demand areas.

Principles applied in consolidation These consolidated financial statements include the accounts of Marathon s majority-owned, controlled subsidiaries and variable interest entities (VIEs) for which Marathon is the primary beneficiary. Investments in entities over which Marathon has significant influence, but not control, are accounted for using the equity method of accounting and are carried at Marathon s share of net assets plus loans and advances. This includes entities in which Marathon holds majority ownership but the minority shareholders have substantive participating rights in the investee. Income from equity method investments represents Marathon s 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.

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

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 functional currency applicable to foreign operating subsidiaries of Marathon is the U.S. dollar since cash flows are denominated principally in U.S. dollars. For these foreign operating subsidiaries, all remeasurement gains and losses are included in net income.

Income per common share Basic income per share is calculated based on the weighted average number of common shares outstanding, including securities exchangeable into common shares. Diluted income per share assumes exercise of stock options and warrants and conversion of convertible debt and preferred securities, provided the effect is not antidilutive.

Segment information Marathon s operations consist of four reportable operating segments:

- 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 United States; 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.

Management has determined that these are its operating segments because these are the components of Marathon (1) that engage in business activities from which revenues are earned and expenses are incurred, (2) whose operating results are regularly reviewed by Marathon s chief operating decision maker (CODM)

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to make decisions about resources to be allocated and to assess performance and (3) for which discrete financial information is available. The CODM is responsible for allocating resources to and assessing performance of Marathon s operating segments. Information regarding assets by segment is not presented because it is not reviewed by the CODM. The CODM is the manager over the E&P and IG segments and the manager of the RM&T and OSM segments reports to the CODM. The segment managers are responsible for allocating resources within the segments, reviewing financial results of components within the segments and assessing the performance of the components. The components within the segments that are separately reviewed and assessed by the CODM in his role as segment manager are aggregable because they have similar economic characteristics. The CODM reviews the financial results of the RM&T and OSM segments at the segment level.

Segment income represents income from continuing operations, net of minority interests and income taxes, attributable to the operating segments. Marathon s 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. Non-cash gains and losses on two long-term natural gas sales contracts in the United Kingdom that are accounted for as derivative instruments and certain non-operating or infrequently occurring items (as determined by the CODM) also are not allocated to operating segments. See the reconciliation of segment income to consolidated net income in Note 9.

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 collectibility 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. Royalties on the production of oil, natural gas and bitumen are either paid in cash or settled through the delivery of volumes. Marathon includes royalties in its revenues and cost of revenues when settlement of the royalties is paid in cash, while royalties settled by the delivery of volumes are excluded from revenues and cost of revenues.

Marathon follows 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.

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, Marathon enters 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. The value of the purchased volumes rarely equals the sales value of the sold volumes. The value differences between purchases and sales are primarily due to (1) grade/quality differentials, (2) location differentials and/or (3) timing differences in those instances when the purchase and sale do not occur in the same month.

For the E&P segment, Marathon enters into matching buy/sell transactions to reposition crude oil from one market center to another to maximize the value received for Marathon s crude oil production. For the RM&T segment, Marathon enters into crude oil matching buy/sell transactions to secure the most profitable refinery supply and enters into refined product matching buy/sell transactions to meet projected customer demand and to secure the required volumes in the most cost-effective manner.

Prior to April 1, 2006, Marathon recorded all such 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, Marathon accounts for matching buy/sell arrangements entered into or modified as exchanges of inventory, except for those arrangements accounted for as derivative instruments.

A portion of Marathon s matching buy/sell transactions are nontraditional derivative instruments, which are described below. Effective for contracts entered into or modified on or after April 1, 2006, the

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income effects of matching buy/sell arrangements accounted for as nontraditional derivative instruments are recognized on a net basis as cost of revenues.

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

Consumer excise taxes Marathon is 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 maturities generally of three months or less.

Accounts receivable and allowance for doubtful accounts Marathon s 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 Marathon s proprietary credit card receivables. Marathon determines the allowance based on historical write-off experience and the volume of proprietary credit card sales. Marathon reviews the allowance quarterly and past-due balances over 180 days are reviewed individually for collectibility. 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.

Traditional derivative instruments Marathon uses derivatives to manage its exposure to commodity price risk, interest rate risk and foreign currency risk. Management has authorized the use of futures, forwards, swaps and combinations of options, including written or net written options, related to the purchase, production or sale of crude oil, natural gas, refined products and ethanol, the fair value of certain assets and liabilities, future interest expense and certain business transactions denominated in foreign currencies. Changes in the fair value of all traditional 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.

Amounts reported in net income are classified as revenues, cost of revenues, depreciation, depletion and amortization or net interest and other financing costs or income based on the nature of the underlying transactions.

As market conditions change, Marathon 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 income and are classified as other income. Any premium received is amortized into net

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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 also recognized in net income and classified as other income.

Nontraditional derivative instruments Certain contracts involving the purchase or sale of commodities are not considered normal purchases or normal sales under generally accepted accounting principles and are required to be accounted for as derivative instruments. Marathon refers to such contracts as nontraditional derivative instruments because, unlike traditional derivative instruments, nontraditional derivative instruments have not been entered into to manage a risk exposure. Such contracts are recorded on the balance sheet at fair value and changes in fair value are recognized in net income and are classified as either revenues or cost of revenues.

In the E&P segment, two long-term natural gas delivery commitment contracts in the United Kingdom are classified as nontraditional 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.

In the RM&T segment, certain physical commodity contracts are classified as nontraditional derivative instruments because certain volumes under these contracts are physically netted at particular delivery locations. The netting process causes all contracts at such delivery locations to be considered derivative instruments. Other physical contracts that management has chosen not to designate as normal purchases or normal sales, which can include contracts that involve flash title, are also accounted for as nontraditional derivative instruments.

Property, plant and equipment Marathon uses the successful efforts method of accounting for oil and gas producing activities. 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) Marathon is 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 of producing oil and natural gas properties are depreciated and depleted on a units-of-production basis.

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. 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.

Marathon evaluates its oil and gas producing properties for impairment of value 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. Marathon evaluates its unproved property investment and records 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 future net cash flows

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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.

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. Such assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If the sum of the expected 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.

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. Marathon has determined that the components of the E&P segment have similar economic characteristics and therefore aggregates the components into a single reporting unit. The OSM segment is comprised of only one component and therefore is a single reporting unit. The RM&T segment is composed of three reporting units: refining and marketing, pipeline transportation and retail marketing. 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 expense.

Intangible assets Intangible assets primarily include technology used in oil sands mining operations, retail marketing tradenames, intangible contract rights and marketing branding agreements. Certain of the marketing tradenames have indefinite lives and therefore are not amortized, but rather are tested for impairment annually and when events or changes in circumstances indicate that the fair value of the intangible asset has been reduced below carrying value. The oil sands mining technology is amortized on a units-of-production basis. The other intangible assets are amortized on a straight-line basis over their estimated useful lives or the expected lives of the related contracts, as applicable, which range from 2 to 22 years. Amortized intangible assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If the sum of the expected 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.

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. Marathon provides 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. For Marathon, 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 Marathon s international oil and gas producing facilities as Marathon currently does not have a legal obligation associated with the retirement of those facilities.

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To a lesser extent, asset retirement obligations also relate to dismantlement and site restoration of oil sands mining facilities and, effective December 31, 2005, 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 due to an indeterminate settlement date of the obligation.

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

Deferred taxes Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases as reported in Marathon s filings with the respective taxing authorities. The realization of deferred tax assets is assessed periodically based on several interrelated factors. These factors include Marathon s 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 Marathon adopted Statement of Financial Accounting Standards (SFAS) No. 123 (Revised 2004), Share-Based Payment, (SFAS No. 123 (R)) as a revision of SFAS No. 123, Accounting for Stock-Based Compensation, as of January 1, 2006. Marathon had previously adopted the fair value method under SFAS No. 123 for grants made, modified or settled on or after January 1, 2003.

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 Marathon s stock price have the most significant impact on the fair value calculation. Marathon has utilized historical data and analyzed current information which reasonably support these assumptions.

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

Effective January 1, 2006, Marathon s 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.

Prior to January 1, 2006, Marathon recorded stock-based compensation expense over the stated vesting period for stock option awards that are subject to specific vesting conditions and specify (1) that an employee vests in the award upon becoming retirement eligible or (2) that the employee will continue to vest in the award after retirement without providing any additional service. Under SFAS No. 123 (R), from the January 1, 2006 date of adoption, such compensation cost is recognized immediately for awards granted to retirement-eligible employees or over the period from the grant date to the retirement eligibility date if retirement eligibility will be reached during the stated vesting period. See Note 24 for more information on stock-based compensation expense, stock option award, stock-based performance award and restricted stock award activity, valuation assumptions and other information required to be disclosed under SFAS No. 123 (R).

Concentrations of credit risk Marathon is 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

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master netting agreements, where appropriate. While no single customer accounts for more than 10 percent of annual revenues, Marathon has significant exposures to United States Steel arising from the transaction discussed in Note 3.

Reclassifications Certain reclassifications of prior years data have been made to conform to 2007 classifications.

2. New Accounting Standards

FSP No. AUG AIR-1 In September 2006, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) No. AUG AIR-1, Accounting for Planned Major Maintenance Activities. This FSP prohibits the use of the accrue-in-advance method of accounting for planned major maintenance activities in annual and interim financial reporting periods. Marathon adopted FSP No. AUG AIR-1 effective January 1, 2007. Prior to adoption, Marathon expensed such costs in the same annual period as incurred; however, estimated annual major maintenance costs were recognized as expense throughout the year on a pro rata basis. As such, the adoption of this FSP has no impact on Marathon s annual consolidated financial statements. The FSP has not been applied retrospectively because the impact on the Company s prior interim consolidated financial statements was not significant.

FIN No. 48 In July 2006, the FASB issued FASB Interpretation (FIN) No. 48, Accounting for Uncertainty in Income Taxes An Interpretation of FASB Statement No. 109. FIN No. 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with SFAS No. 109, Accounting for Income Taxes. FIN No. 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The new standard also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, transition and disclosure. Marathon adopted FIN No. 48 effective January 1, 2007, and adoption did not have a significant effect on its consolidated results of operations, financial position or cash flows. See Note 11 for other disclosures required by FIN No. 48.

SFAS No. 156 In March 2006, the FASB issued SFAS No. 156, Accounting for Servicing of Financial Assets An Amendment of FASB Statement No. 140. This statement amends SFAS No. 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities, with respect to the accounting for separately recognized servicing assets and servicing liabilities. Marathon adopted SFAS No. 156 effective January 1, 2007, and adoption did not have a significant effect on its consolidated results of operations, financial position or cash flows.

SFAS No. 155 In February 2006, the FASB issued SFAS No. 155, Accounting for Certain Hybrid Financial Instruments An Amendment of FASB Statements No. 133 and 140. SFAS No. 155 simplifies the accounting for certain hybrid financial instruments, eliminates the interim FASB guidance which provided that beneficial interests in securitized financial assets are not subject to the provisions of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, and eliminates the restriction on the passive derivative instruments that a qualifying special-purpose entity may hold. Effective January 1, 2007, Marathon adopted the provisions of SFAS No. 155 prospectively for all financial instruments acquired or issued on or after January 1, 2007. Adoption of this statement did not have a significant effect on Marathon s consolidated results of operations, financial position or cash flows.

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. Marathon adopted SFAS No. 158 prospectively as of December 31, 2006 and has recognized the funded status of its plans in the consolidated balance sheets. The adoption of SFAS No. 158 had no impact on Marathon s measurement date as the Company has historically measured the plan assets and benefit obligations of its pension and other postretirement plans as of December 31. See Note 22 for additional disclosures regarding defined benefit pension and other postretirement plans required by SFAS No. 158.

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The following table illustrates the incremental effect of applying SFAS No. 158 on individual line items of the balance sheet as of December 31, 2006.

(In millions)	Before Application of SFAS No. 158	Adjustments	After Application of SFAS No. 158
Prepaid pensions	$ 229	$ (229)	$
Equity method investments	1,545	(6)	1,539
Total assets	31,066	(235)	30,831
Payroll and benefits payable	$ 384	$ 25	$ 409
Long-term deferred income taxes	2,183	(286)	1,897
Defined benefit postretirement plan obligations	$ 870	$ 375	$ 1,245
Deferred credits and other liabilities	397	(6)	391
Total liabilities	15,598	108	15,706
Accumulated other comprehensive loss	(25)	(343)	(368)
Total stockholders equity	$ 14,950	$ (343)	$ 14,607

SAB No. 108 In September 2006, the Securities and Exchange Commission issued Staff Accounting Bulletin (SAB) No. 108, Financial Statements Considering the Effects of Prior Year Misstatements When Quantifying Misstatements in Current Year Financial Statements. SAB No. 108 addresses how a registrant should quantify the effect of an error in the financial statements for purposes of assessing materiality and requires that the effect be computed using both the current year income statement perspective (rollover) and the year end balance sheet perspective (iron curtain) methods for fiscal years ending after November 15, 2006. If a change in the method of quantifying errors is required under SAB No. 108, this represents a change in accounting policy; therefore, if the use of both methods results in a larger, material misstatement than the previously applied method, the financial statements must be adjusted. SAB No. 108 allows the cumulative effect of such adjustments to be made to opening retained earnings upon adoption. Marathon adopted SAB No. 108 for the year ended December 31, 2006, and adoption did not have an effect on Marathon s consolidated results of operations, financial position or cash flows.

EITF Issue No. 06-03 In June 2006, the FASB ratified the consensus reached by the EITF regarding Issue No. 06-03, How Taxes Collected from Customers and Remitted to Governmental Authorities Should be Presented in the Income Statement (That Is, Gross versus Net Presentation). Included in the scope of this issue are any taxes assessed by a governmental authority that are imposed on and concurrent with a specific revenue-producing transaction between a seller and a customer. The EITF concluded that the presentation of such taxes on a gross basis (included in revenues and costs) or a net basis (excluded from revenues) is an accounting policy decision that should be disclosed pursuant to Accounting Principles Board (APB) Opinion No. 22, Disclosure of Accounting Policies. In addition, the amounts of such taxes reported on a gross basis must be disclosed if those tax amounts are significant. The policy disclosures required by this consensus are included in Note 1 under the heading Consumer excise taxes and the taxes reported on a gross basis are presented separately as consumer excise taxes in the consolidated statements of income.

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, Marathon 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, which are discussed below). In a typical matching buy/sell transaction, Marathon enters 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

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EITF Issue No. 04-13, Marathon recorded such matching buy/sell transactions in both revenues and cost of revenues as separate sale and purchase transactions. Upon adoption, these transactions are accounted for as exchanges of inventory.

The scope of EITF Issue No. 04-13 excludes matching buy/sell arrangements that are accounted for as derivative instruments. A portion of Marathon s matching buy/sell transactions are nontraditional derivative instruments, which are discussed in Note 1. Although the accounting for nontraditional derivative instruments is outside the scope of EITF Issue No. 04-13, the conclusions reached in that consensus caused Marathon to reconsider the guidance in EITF Issue No. 03-11, Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not Held for Trading Purposes as Defined in Issue No. 02-3. As a result, effective for contracts entered into or modified on or after April 1, 2006, the effects of matching buy/sell arrangements accounted for as nontraditional derivative instruments are recognized on a net basis in net income and are classified as cost of revenues. Prior to this change, Marathon recorded these transactions in both revenues and cost of revenues as separate sale and purchase transactions. This change in accounting principle is being applied on a prospective basis because it is impracticable to apply the change on a retrospective basis.

Transactions arising from matching buy/sell arrangements entered into before April 1, 2006 will continue to be reported as separate sale and purchase transactions.

The adoption of EITF Issue No. 04-13 and the change in the accounting for nontraditional derivative instruments had 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.

SFAS No. 123 (Revised 2004) In December 2004, the FASB issued SFAS No. 123 (R), Share-Based Payment, as a revision of SFAS No. 123, Accounting for Stock-Based Compensation. This statement requires entities to measure the cost of employee services received in exchange for an award of equity instruments based on the fair value of the award on the grant date. That cost is recognized over the period during which an employee is required to provide service in exchange for the award, usually the vesting period. In addition, awards classified as liabilities are remeasured at fair value each reporting period. Marathon had previously adopted the fair value method under SFAS No. 123 for grants made, modified or settled on or after January 1, 2003.

SFAS No. 123(R) also requires a company to calculate the pool of excess tax benefits available to absorb tax deficiencies recognized subsequent to adopting the statement. In November 2005, the FASB issued FSP No. 123R-3, Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards, to provide an alternative transition election (the short-cut method) to account for the tax effects of share-based payment awards to employees. Marathon elected the long-form method to determine its pool of excess tax benefits as of January 1, 2006.

Marathon adopted SFAS No. 123(R) as of January 1, 2006, for all awards granted, modified or cancelled after adoption and for the unvested portion of awards outstanding at January 1, 2006. At the date of adoption, SFAS No. 123(R) requires that an assumed forfeiture rate be applied to any unvested awards and that awards classified as liabilities be measured at fair value. Prior to adopting SFAS No. 123(R), Marathon recognized forfeitures as they occurred and applied the intrinsic value method to awards classified as liabilities. The adoption did not have a significant effect on Marathon s consolidated results of operations, financial position or cash flows.

SFAS No. 151 Effective January 1, 2006, Marathon adopted SFAS No. 151, Inventory Costs an amendment of ARB No. 43, Chapter 4. This statement requires that items such as idle facility expense, excessive spoilage, double freight and re-handling costs be recognized as a current-period charge. The adoption did not have a significant effect on Marathon s consolidated results of operations, financial position or cash flows.

SFAS No. 154 Effective January 1, 2006, Marathon adopted SFAS No. 154, Accounting Changes and Error Corrections A Replacement of APB Opinion No. 20 and FASB Statement No. 3. SFAS No. 154 requires companies to recognize (1) voluntary changes in accounting principle and (2) changes required by a new accounting pronouncement, when the pronouncement does not include specific transition provisions, retrospectively to prior periods financial statements, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change.

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FIN No. 47 In March 2005, the FASB issued FIN No. 47, Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No. 143. This interpretation clarifies that an entity is required to recognize a liability for a legal obligation to perform asset retirement activities when the retirement is conditional on a future event if the liability s fair value can be reasonably estimated. If the liability s fair value cannot be reasonably estimated, then the entity must disclose (1) a description of the obligation, (2) the fact that a liability has not been recognized because the fair value cannot be reasonably estimated and (3) the reasons why the fair value cannot be reasonably estimated. FIN No. 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. Marathon adopted FIN No. 47 as of December 31, 2005. A charge of $19 million, net of taxes of $12 million, related to adopting FIN No. 47 was recognized as a cumulative effect of a change in accounting principle in 2005. At the time of adoption, total assets increased $22 million and total liabilities increased $41 million.

The pro forma net income and net income per share effect as if FIN No. 47 had been applied during 2005 is not significantly different than the amounts reported. The total amount of the liability for asset retirement obligations at the beginning of 2005 would have been $527 million if FIN No. 47 had been applied as of that date. The pro forma impact of the adoption of FIN No. 47 on this unaudited pro forma amount has been measured using the information, assumptions and interest rates used to measure the obligation recognized upon adoption of FIN No. 47.

FSP No. FAS 19-1 Effective January 1, 2005, Marathon adopted FSP No. FAS 19-1, Accounting for Suspended Well Costs, which amended the guidance for deferred exploratory well costs in SFAS No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies. SFAS No. 19 requires costs of drilling exploratory wells to be capitalized pending determination of whether the well has found proved reserves. When a classification of proved reserves cannot yet be made, FSP No. FAS 19-1 allows exploratory well costs to continue to be capitalized when (1) the well has found a sufficient quantity of reserves to justify completion as a producing well and (2) the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project. Marathon s accounting policy for deferred exploratory well costs was in accordance with FSP No. FAS 19-1 prior to its adoption. FSP No. FAS 19-1 also requires certain disclosures to be made regarding capitalized exploratory well costs which are included in Note 14.

3. Information about United States Steel

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

Financial Matters Agreement Marathon and United States Steel have 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 Separation, United States Steel will provide for Marathon s 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 from Marathon, 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 is the sole general partner of Clairton 1314B Partnership, L.P., which owns certain cokemaking facilities formerly owned by United States Steel. Marathon has guaranteed to the limited partners all obligations of United States Steel under the partnership documents. The Financial Matters Agreement requires United States Steel to use commercially reasonable efforts to have Marathon released from its obligations under this guarantee. United States Steel may dissolve the partnership under certain circumstances, including if it is required to fund accumulated cash shortfalls of the partnership in excess of $150 million. In addition to the normal commitments of a general partner, United States Steel has indemnified the limited partners for certain income tax exposures.

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The Financial Matters Agreement requires Marathon 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 Marathon s consent.

Tax Sharing Agreement Marathon and United States Steel have 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 Separation date and taxes resulting from transactions effected in connection with the Separation.

In 2006 and 2005, in accordance with the terms of the Tax Sharing Agreement, Marathon paid $35 million and $6 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. Variable Interest Entities

Equatorial Guinea LNG Holdings Limited (EGHoldings), in which Marathon holds a 60 percent interest, was formed for the purpose of constructing and operating an LNG production facility. During facility construction, EGHoldings was a VIE that was consolidated by Marathon because Marathon was its primary beneficiary. Once the LNG production facility commenced its primary operations and began to generate revenue in May 2007, EGHoldings was no longer a VIE. Effective May 1, 2007, Marathon no longer consolidates EGHoldings, despite the fact that the Company holds majority ownership, because the minority shareholders have rights limiting Marathon s ability to exercise control over the entity. Marathon s investment is accounted for prospectively using the equity method of accounting, is carried at the Company s share of net assets plus loans and advances, which totaled $1.014 billion as of December 31, 2007, and is included in equity method investments in the consolidated balance sheet as of that date. The Andersons Marathon Ethanol LLC, a joint venture in which Marathon and its partner each hold a 50 percent interest and which was formed in 2006 for the purpose of constructing and operating one or more ethanol production plants, is a VIE that is not consolidated. As of December 31, 2007, Marathon had invested $38 million in The Andersons Marathon Ethanol LLC.

5. Related Party Transactions

Related parties during 2007, 2006 and 2005 include:

- Sociedad Nacional de Gas de Guinea Ecuatorial (SONAGAS), which has held a 25 percent ownership interest in EGHoldings, since November 14, 2006;

- Mitsui & Co., Ltd. (Mitsui) and Marubeni Corporation (Marubeni), which have held 8.5 percent and 6.5 percent ownership interests in EGHoldings since July 25, 2005;

Compania Nacional de Petroleos de Guinea Ecuatorial (GEPetrol), which held a 25 percent ownership interest in EGHoldings until November 14, 2006;

Ashland Inc. (Ashland), which held a 38 percent ownership interest in Marathon Petroleum Company LLC (MPC), a consolidated subsidiary, until June 30, 2005; and

Equity method investees.

SONAGAS, Mitsui and Marubeni ceased being related parties on May 1, 2007, upon the deconsolidation of EGHoldings discussed in Note 4. At that date, EGHoldings became a related party as it became an equity method investee.

Management believes that transactions with related parties were conducted under terms comparable to those with unrelated parties.

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Related party sales to Pilot Travel Centers LLC (PTC) and Ashland consist primarily of petroleum products. Revenues from related parties were as follows:

(In millions)	**2007**	2006	2005
Equity method investees:			
PTC	**$ 1,556**	$ 1,420	$ 1,205
Centennial Pipeline LLC (Centennial)	**27**	28	47
Other equity method investees	**42**	18	18
Ashland			132
Total	**$ 1,625**	$ 1,466	$ 1,402

Purchases from related parties were as follows:

(In millions)	**2007**	2006	2005
Equity method investees:			
Alba Plant LLC	**$ 131**	$	$
LOOP LLC	**43**	54	49
Centennial	**57**	53	73
Other equity method investees	**132**	103	91
Ashland			12
Total	**$ 363**	$ 210	$ 225

Current receivables from related parties were as follows:

(In millions) December 31	**2007**	2006
Equity method investees:		
EGHoldings	**$ 18**	$
PTC	**45**	41
Other equity method investees	**16**	9
Other related parties		13
Total	**$ 79**	$ 63

Payables to related parties were as follows:

(In millions) December 31	**2007**	2006
SONAGAS	**$**	$ 229
Equity method investees:		
Alba Plant LLC	**19**	15
Other equity method investees	**25**	17
Other related parties		3
Total	**$ 44**	$ 264

Cash of $234 million held in escrow for future capital contributions from SONAGAS to EGHoldings was classified as restricted cash by EGHoldings and was included in other noncurrent assets as of December 31, 2006. As discussed in Note 4, EGHoldings is no longer consolidated effective May 1, 2007.

6. Acquisitions

Western Oil Sands Inc. On October 18, 2007, Marathon completed the acquisition of all the outstanding shares of Western Oil Sands Inc. (Western) for cash and securities of $5.833 billion. 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, Marathon s 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.

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The purchase price for the Western acquisition is 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 billion 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 Marathon s average common stock price over the trading days between July 26 and August 1, 2007 (the days surrounding the announcement of the transaction).

The primary reasons for the acquisition and the principal factors contributing to a purchase price resulting in goodwill are: access to the long-life 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 Marathon s 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 following table summarizes the estimated fair values of the assets and liabilities acquired as of October 18, 2007. Marathon is in the process of finalizing the fair value estimates for certain assets and liabilities; thus the allocation of the purchase price is preliminary.

(In millions)	
Current assets:	
Cash and cash equivalents	$ 44
Receivables	341
Inventories	26
Other current assets	40
Total current assets acquired	451
Property, plant and equipment	6,842
Goodwill	1,508
Intangible assets	113
Other noncurrent assets	10
Total assets acquired	$ 8,924
Current liabilities:	
Accounts payable	$ 339
Current portion of long-term debt	50
Deferred income taxes	48
Other current liabilities	19
Total current liabilities assumed	456
Long-term debt	1,013
Deferred income taxes	1,502
Asset retirement obligations	31

Other liabilities	89
Total liabilities assumed	3,091
Net assets acquired	$ 5,833

The goodwill arising from the purchase price allocation was $1.508 billion, of which $1.437 billion was assigned to the Oil Sands Mining Segment $71 million was assigned to the E&P segment. None of the goodwill is deductible for tax purposes.

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The following unaudited pro forma data is 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

Minority interest in MPC On June 30, 2005, Marathon acquired the 38 percent ownership interest in Marathon Ashland Petroleum LLC (MAP) previously held by Ashland. In addition, Marathon 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 effective September 1, 2005. The acquisition was accounted for under the purchase method of accounting and, as such, Marathon s results of operations include the results of the acquired businesses from June 30, 2005. The purchase price is as follows:

(In millions)	
Cash[(a)]	$ 487
MPC accounts receivable[(a)]	911
Marathon common stock[(b)]	955
Estimated additional consideration related to tax matters	88
Transaction-related costs	10
Purchase price	2,451
Assumption of debt[(c)]	1,920
Total consideration including debt assumption[(d)]	$ 4,371

(a) The MAP Limited Liability Company Agreement was amended to eliminate the requirement for MPC to make quarterly cash distributions to Marathon and Ashland between the date the principal transaction agreements were signed and the closing of the acquisition. Cash and MPC accounts receivable above include $506 million representing Ashland s 38 percent of MPC s distributable cash as of June 30, 2005.

(b) Ashland shareholders received 35 million shares valued at $27.23 per share, which was Marathon s average common stock price over the trading days between June 23 and June 29, 2005. The exchange ratio was designed to provide an aggregate number of Marathon shares worth $915 million based on Marathon s average common stock price for each of the 20 consecutive trading days ending with the third complete trading day prior to June 30, 2005.

(c) Assumed debt was repaid on July 1, 2005.

(d) Marathon is entitled to certain tax deductions related to businesses previously owned by Ashland. However, pursuant to the terms of the tax matters agreement, Marathon has agreed to reimburse Ashland for a portion of the tax benefits associated with these deductions. This additional consideration will be included in the purchase price as amounts owed to Ashland are identified. Additions to the purchase price for such amounts were $13 million and $17 million in 2007 and 2006.

The primary reasons for the acquisition and the principal factors that contributed to a purchase price that resulted in the recognition of goodwill were:

Marathon believed the outlook for the refining and marketing business was attractive in MPC s core areas of operation. Complete ownership of MPC provided Marathon the opportunity to leverage MPC s access to premium U.S. markets where Marathon expected the levels of demand to remain high for the foreseeable future;

The acquisition increased Marathon s participation in the RM&T business without the risks commonly associated with integrating a newly acquired business;

MPC provided Marathon with an increased source of cash flow which Marathon believed enhanced the geographical balance in its overall risk portfolio;

Marathon anticipated the transaction would be accretive to income per share;

The acquisition eliminated the timing and valuation uncertainties associated with the exercise of the Put/Call, Registration Rights and Standstill Agreement entered into with the formation of MPC in 1998, as well as the associated premium and discount; and

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The acquisition eliminated the possibility that a misalignment of Ashland s and Marathon s interests, as co-owners of MPC, could adversely affect MPC s future growth and financial performance.

The following table summarizes the estimated fair values of the assets acquired and liabilities assumed as of June 30, 2005.

(In millions)	
Current assets:	
Cash and cash equivalents	$ 518
Receivables	1,080
Inventories	1,866
Other current assets	28
Total current assets acquired	3,492
Equity method investments	472
Property, plant and equipment	2,671
Goodwill	846
Intangible assets	112
Other noncurrent assets	20
Total assets acquired	$ 7,613
Current liabilities:	
Notes payable	$ 1,920
Deferred income taxes	669
Other current liabilities	1,674
Total current liabilities assumed	4,263
Long-term debt	16
Deferred income taxes	368
Defined benefit postretirement plan obligations	470
Other liabilities	45
Total liabilities assumed	$ 5,162
Net assets acquired	$ 2,451

The goodwill arising from the purchase price allocation was $846 million, which was assigned to the RM&T segment. None of the goodwill is deductible for tax purposes. Of the $112 million allocated to intangible assets, $49 million was allocated to retail marketing tradenames with indefinite lives.

The purchase price allocated to equity method investments is $230 million higher than the underlying net assets of the investees. This excess will be amortized over the expected useful lives of the underlying assets except for $144 million of the excess related to goodwill.

Libya re-entry On December 29, 2005, Marathon, in conjunction with its partners in the former Oasis Group, entered into an agreement with the National Oil Corporation of Libya to return to its oil and natural gas exploration and production operations in the Waha concessions in Libya. Marathon holds a 16.33 percent interest in the Waha concessions and was required to cease operations there in 1986 to comply with U.S. government sanctions. Over time, Marathon had written off all its assets in Libya. The re-entry terms included a 25-year extension of the concessions to 2030 through 2034 and payments from Marathon of $520 million and $198 million, which were made in January and December 2006.

The primary reasons for the transaction and the principal factors that contributed to a purchase price that resulted in the recognition of goodwill include the fact that the re-entry allows Marathon to expand its exploration and production operations without many of the risks commonly associated with integrating a newly acquired business including having a trained workforce in place that has maintained operations and added to the hydrocarbon resource during the absence of Marathon and its partners. The transaction also could assist Marathon in identifying and participating in potential future projects in Libya.

The operational re-entry date under the terms of the agreement was January 1, 2006; therefore, Marathon s consolidated results of operations for 2005 do not include any results from the operations of the Waha concessions. The transaction was accounted for under the purchase method of accounting.

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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 Marathon s 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 following table summarizes the estimated fair values of the assets acquired and liabilities assumed as of December 29, 2005.

(In millions)	
Current assets:	
Inventories	$ 10
Other current assets	7
Total current assets acquired	17
Property, plant and equipment	719
Deferred income tax assets	175
Goodwill	309
Total assets acquired	$ 1,220
Current liabilities:	
Accounts payable	$ 17
Other liabilities	6
Deferred income tax liabilities	479
Total liabilities assumed	$ 502
Net assets acquired	$ 718

The goodwill arising from the purchase price allocation was $309 million, which was assigned to the E&P segment. None of the goodwill is deductible for tax purposes.

The following unaudited pro forma data is as if the acquisition of the minority interest in MPC and the re-entry to the Libya concessions had been consummated at the beginning of 2005. 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)	2005
Revenues and other income	$ 65,614
Income from continuing operations	3,315
Net income	3,341
Per share data:	
Income from continuing operations basic	$ 4.54
Income from continuing operations diluted	$ 4.51
Net income basic	$ 4.58
Net income diluted	$ 4.54

7. Discontinued Operations

On June 2, 2006, Marathon sold its Russian oil exploration and production businesses in the Khanty-Mansiysk region of western Siberia. Under the terms of the agreement, Marathon 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 as discussed in Note 11. 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.

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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 all periods presented. Revenues applicable to discontinued operations were $173 million and $325 million for 2006 and 2005. Pretax income from discontinued operations was $45 million and $61 million for 2006 and 2005.

8. Income per Common Share

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

	2007		2006		2005	
(In millions, except per share data)	**Basic**	**Diluted**	Basic	Diluted	Basic	Diluted
Income from continuing operations	**$ 3,948**	**$ 3,948**	$ 4,957	$ 4,957	$ 3,006	$ 3,006
Discontinued operations	**8**	**8**	277	277	45	45
Cumulative effect of change in accounting principle					(19)	(19)
Net income	**$ 3,956**	**$ 3,956**	$ 5,234	$ 5,234	$ 3,032	$ 3,032
Weighted average common shares outstanding	**690**	**690**	716	716	712	712
Effect of dilutive securities		**5**		6		6
Weighted average common shares, including dilutive effect	**690**	**695**	716	722	712	718
Per share:						
Income from continuing operations	**$ 5.72**	**$ 5.68**	$ 6.92	$ 6.87	$ 4.22	$ 4.19
Discontinued operations	**$ 0.01**	**$ 0.01**	$ 0.39	$ 0.38	$ 0.07	$ 0.06
Cumulative effect of change in accounting principle	**$**	**$**	$	$	$ (0.03)	$ (0.03)
Net income	**$ 5.73**	**$ 5.69**	$ 7.31	$ 7.25	$ 4.26	$ 4.22

The per share calculations above exclude 3.2 million stock options in 2007 that were antidilutive. There were no antidilutive stock options in 2006 and 2005.

9. Segment Information

As discussed in Note 7, the Russian businesses that were sold in June 2006 have been accounted for as discontinued operations. Segment information for all presented periods excludes the amounts for these Russian operations.

As discussed in Note 6, Marathon acquired Western in October 2007. The acquisition was accounted for under the purchase method of accounting and, as such, Marathon s 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.

Revenues by product line were:

(In millions)	**2007**	2006	2005
Refined products	**$ 49,718**	$ 45,511	$ 40,040
Merchandise	**2,975**	2,871	2,689
Liquid hydrocarbons	**8,919**	12,531	16,352
Natural gas	**2,629**	3,742	3,675
Transportation and other	**311**	241	230
Total	**$ 64,552**	$ 64,896	$ 62,986

Matching buy/sell transactions by product line included above were:

(In millions)	**2007**	2006	2005
Refined products	**$**	$ 645	$ 1,817
Liquid hydrocarbons	**127**	4,812	10,819
Total	**$ 127**	$ 5,457	$ 12,636

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	E&P	OSM	RM&T	IG	Total
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 long-term 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 interests 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 long-term 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 interests 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
2005					
Revenues:					
Customer	$ 7,320	$	$ 54,414	$ 236	$ 61,970
Intersegment[(a)]	678		198		876
Related parties	11		1,391		1,402
Segment revenues	8,009		56,003	236	64,248
Elimination of intersegment revenues	(678)		(198)		(876)
Loss on long-term U.K. natural gas contracts	(386)				(386)
Total revenues	$ 6,945	$	$ 55,805	$ 236	$ 62,986
Segment income	$ 1,887	$	$ 1,628	$ 55	$ 3,570
Income from equity method investments	69		137	59	265

Depreciation, depletion and amortization[b]	794	468	8	1,270
Minority interests in (income) loss of subsidiaries[b]		(376)	8	(368)
Income tax provision (benefit)[b]	1,030	1,007	(7)	2,030
Capital expenditures[c][d]	1,366	841	571	2,778

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

(b) Differences between segment totals and Marathon 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 the reconciliation below.

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

(d) Through April 2007, Integrated Gas segment capital expenditures include EGHoldings at 100 percent. As discussed in Note 4, effective May 1, 2007, Marathon no longer consolidates EGHoldings and its investment in EGHoldings is accounted for under the equity method of accounting; therefore EGHoldings capital expenditures subsequent to April 2007 are not included in Marathon s capital expenditures.

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

(In millions)	**2007**	2006	2005
Segment income	**$ 3,875**	$ 4,814	$ 3,570
Items not allocated to segments, net of income taxes:			
Corporate and other unallocated items	**(104)**	(212)	(377)
Gain (loss) on long-term U.K. natural gas contracts	**(118)**	232	(223)
Gain on foreign currency derivative instruments	**112**		
Deferred income taxes tax legislation changes	**193**	21	15
other adjustments[(a)]		93	
Gain on dispositions	**8**	274	
Loss on early extinguishment of debt	**(10)**	(22)	
Discontinued operations		34	45
Gain on sale of minority interests in EGHoldings			21
Cumulative effect of change in accounting principle			(19)
Net income	**$ 3,956**	$ 5,234	$ 3,032

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

The following summarizes revenues from external customers by geographic area.

(In millions)	**2007**	2006	2005
United States	**$ 59,302**	$ 59,723	$ 60,242
International	**5,250**	5,173	2,744
Total	**$ 64,552**	$ 64,896	$ 62,986

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

(In millions)	**2007**	2006
United States	**$ 13,133**	$ 11,365
Canada	**6,980**	
Equatorial Guinea	**2,842**	3,186
Other international	**4,393**	3,675
Total	**$ 27,348**	$ 18,226

10. Other Items

Net interest and other financial income (costs)

(In millions)	**2007**	2006	2005
Interest and other financial income:			

Interest income	**$ 144**	$ 129	$ 77
Foreign currency gains (losses)	**2**	16	(17)
Total	**146**	145	60
Interest and other financing costs:			
Interest incurred[(a)]	**290**	245	257
Loss on interest rate swaps	**15**	16	
Interest capitalized	**(214)**	(152)	(83)
Net interest expense	**91**	109	174
Other	**14**	(1)	32
Total	**105**	108	206
Net interest and other financial income (costs)	**$ 41**	$ 37	$ (146)

(a) Excludes $30 million, $33 million and $34 million paid by United States Steel in 2007, 2006 and 2005 on assumed debt.

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

(In millions)	**2007**	2006	2005
Net interest and other financing costs	**$ 2**	$ 16	$ (17)
Provision for income taxes	**18**	(22)	24
Aggregate foreign currency gains (losses)	**$ 20**	$ (6)	$ 7

11. Income Taxes

Income tax provisions (benefits) were:

	2007			2006			2005		
(In millions)	**Current**	**Deferred**	**Total**	Current	Deferred	Total	Current	Deferred	Total
Federal	**$ 1,290**	**$ (2)**	**$ 1,288**	$ 1,579	$ 72	$ 1,651	$ 1,225	$ 14	$ 1,239
State and local	**184**	**22**	**206**	230	30	260	171	12	183
Foreign	**1,774**	**(367)**	**1,407**	1,945	166	2,111	523	(231)	292
Total	**$ 3,248**	**$ (347)**	**$ 2,901**	$ 3,754	$ 268	$ 4,022	$ 1,919	$ (205)	$ 1,714

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)	**2007**	2006	2005
Statutory rate applied to income from continuing operations before income taxes	**$ 2,397**	$ 3,143	$ 1,652
Effects of foreign operations, including foreign tax credits [(a)]	**671**	909	(39)
State and local income taxes, net of federal income tax effects	**134**	170	134
Credits other than foreign tax credits	**(3)**	(2)	(2)
Domestic manufacturing deduction	**(64)**	(47)	(39)
Excess capital losses generated			23
Effects of partially-owned companies	**(5)**	(6)	(4)
Effects of enacted changes in tax laws [(b)]	**(193)**	(21)	(15)
Adjustment of prior years federal income taxes (c)	**(27)**	(119)	10
Other	**(9)**	(5)	(6)
Provision for income taxes	**$ 2,901**	$ 4,022	$ 1,714

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

(b) 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, and in 2005, the state of Ohio enacted legislation that phased out its income-based franchise taxes.

(c) The 2006 adjustment of prior years federal income taxes is 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	**2007**	2006
Deferred tax assets:		
Employee benefits	**$ 703**	$ 730
Operating loss carryforwards (a)	**1,596**	1,016
Derivative instruments	**284**	81
Foreign tax credits (b)	**838**	527
Other	**169**	200
Valuation allowances		
Federal [c]	**(29)**	(19)
State	**(55)**	(59)
Foreign (d)	**(917)**	(611)
Total deferred tax assets	**2,589**	1,865
Deferred tax liabilities:		
Property, plant and equipment (e)	**4,610**	2,951
Inventories	**652**	708
Investments in subsidiaries and affiliates	**987**	552
Other	**89**	100
Total deferred tax liabilities	**6,338**	4,311
Net deferred tax liabilities	**$ 3,749**	$ 2,446

(a) At December 31, 2007, foreign operating loss carryforwards primarily include $1.214 billion for Norway regular income tax, $1.677 billion for Norway special petroleum tax and $540 million for Angola income tax. The Norway and Angola operating loss carryforwards have no expiration dates. The remainder of foreign carryforwards are in several other foreign jurisdictions, the majority of which expire in 2008 through 2020. State operating loss carryforwards of $765 million expire in 2008 through 2025. The state operating loss carryforwards primarily relate to the period prior to the Separation and are offset by valuation allowances.

(b) The Company s expectation regarding its 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 Marathon s tax profile in the years that such credits may be claimed.

(c) Federal valuation allowances 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 Marathon s Russian oil exploration and production businesses. Federal valuation allowances increased $63 million in 2005 reflecting valuation allowances established for deferred tax assets generated in 2005, primarily related to Marathon s re-entry into Libya of $38 million and excess capital losses related to certain derivative instruments and an asset sale of $30 million.

(d) Foreign valuation allowances increased $306 million, $176 million and $70 million in 2007, 2006 and 2005 primarily as a result of net operating loss carryforwards generated in those years in Norway, Angola and several other jurisdictions.

(e) Deferred tax liabilities for property, plant, and equipment increased $1.659 billion in 2007 primarily due to a $1.338 billion increase attributable to Marathon s acquisition of Western.

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

(In millions) December 31	**2007**	2006
Assets:		
Other current assets	**$ 2**	$ 4
Other noncurrent assets	**185**	78
Liabilities:		
Current deferred income taxes	**547**	631
Noncurrent deferred income taxes	**3,389**	1,897

Net deferred tax liabilities	**$ 3,749**	$ 2,446

Marathon is continuously undergoing examination of its U.S. federal income tax returns by the Internal Revenue Service. Such audits have been completed through the 2003 tax year. The audit of the 2004 and 2005 U.S. federal income tax returns commenced in May 2006 and is ongoing. Marathon believes it has made adequate provision for federal income taxes and interest which may become payable for years not yet settled. Further, Marathon is routinely involved in U.S. state and local income tax audits and foreign jurisdiction tax audits. Marathon believes all other audits will be resolved within the amounts paid and/or provided for these

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liabilities. As of December 31, 2007, Marathon s income tax returns remain subject to examination in the following major tax jurisdictions for the tax years indicated.

United States [(a)]	2000 2006
Canada	2000 2006
Equatorial Guinea	2006
Libya	2006
United Kingdom	2005 2006

(a) Includes federal, state and local jurisdictions.

Total unrecognized tax benefits were $48 million upon adoption of FIN No. 48 as of January 1, 2007, and were $40 million as of December 31, 2007. If the unrecognized tax benefits as of December 31, 2007 were recognized, $29 million would affect Marathon s effective income tax rate. There are $23 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 2008.

The following table summarizes the activity in unrecognized tax benefits for 2007.

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

In connection with the adoption of FIN No. 48, Marathon 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, Marathon recorded such interest as part of net interest and other financing costs and such penalties as selling, general and administrative expenses. Interest and penalties were a net $8 million credit to income for the year ended December 31, 2007. As of December 31, 2007 and 2006, $15 million and $17 million of interest and penalties were accrued related to income taxes.

Pretax income from continuing operations included amounts attributable to foreign sources of $2.900 billion in 2007, $3.570 billion in 2006 and $1.061 billion in 2005.

Undistributed income of certain consolidated foreign subsidiaries at December 31, 2007 amounted to $1.739 billion for which no deferred U.S. income tax provision has been recorded because Marathon intends to permanently reinvest such income in those foreign operations. If such income was not permanently reinvested, income tax expense of $609 million would have been incurred.

12. Inventories

(In millions)	December 31	**2007**	2006
Liquid hydrocarbons, natural gas and bitumen		**$ 1,203**	$ 1,136

Refined products and merchandise	**1,792**	1,812
Supplies and sundry items	**282**	225
Total (at cost)	**$ 3,277**	$ 3,173

The LIFO method accounted for 89 percent and 90 percent of total inventory value at December 31, 2007 and 2006. Current acquisition costs were estimated to exceed the LIFO inventory value at December 31, 2007 and 2006 by $4.034 billion and $1.682 billion.

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13. Equity Method Investments

(In millions) December 31	2007	2006
EGHoldings [(a)]	**$ 1,014**	$
Alba Plant LLC	**395**	420
Atlantic Methanol Production Company LLC	**245**	257
Pilot Travel Centers LLC	**493**	510
LOOP LLC	**183**	156
Other	**300**	196
Total	**$ 2,630**	$ 1,539

(a) As discussed in Note 4, Marathon no longer consolidates EGHoldings effective May 1, 2007. Marathon s investment is accounted for prospectively using the equity method of accounting and therefore EGHoldings results for May 1, 2007 through December 31, 2007 are included in the income data below.

Summarized financial information of investees accounted for by the equity method of accounting follows:

(In millions)	2007	2006	2005
Income data year:			
Revenues and other income	**$ 14,133**	$ 11,873	$ 10,088
Income from operations	**1,098**	746	556
Net income	**1,038**	710	474
Balance sheet data December 31:			
Current assets	**$ 1,279**	$ 817	
Noncurrent assets	**5,998**	3,637	
Current liabilities	**1,512**	755	
Noncurrent liabilities	**1,378**	1,119	

Marathon s carrying value of its equity method investments is $356 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 $159 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 $502 million in 2007, $191 million in 2006 and $200 million in 2005.

14. Property, Plant and Equipment

(In millions) December 31	2007	2006
Exploration and production	**$ 21,232**	$ 18,894
Oil sands mining and bitumen upgrading	**6,691**	
Refining	**6,462**	5,238
Marketing	**2,123**	2,015
Transportation	**2,331**	2,173

Gas liquefaction [(a)]	**26**	1,321
Other	**667**	585
Total	**$ 39,532**	$ 30,226
Less accumulated depreciation, depletion and amortization	**14,857**	13,573
Net property, plant and equipment	**$ 24,675**	$ 16,653

(a) Through April 2007, gas liquefaction property, plant and equipment included EGHoldings at 100 percent. As discussed in Note 4, effective May 1, 2007, Marathon no longer consolidates EGHoldings and its investment in EGHoldings is accounted for under the equity method of accounting; therefore EGHoldings property, plant and equipment balance subsequent to April 2007 is not included in Marathon s property, plant and equipment.

Property, plant and equipment includes gross assets acquired under capital leases of $74 million and $79 million at December 31, 2007 and 2006, with related amounts in accumulated depreciation, depletion and amortization of $13 million and $10 million at December 31, 2007 and 2006.

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Deferred exploratory well costs were as follows:

(Dollars in millions) December 31	**2007**	2006	2005
Amounts capitalized less than one year after completion of drilling	**$ 683**	$ 377	$ 304
Amounts capitalized greater than one year after completion of drilling	**100**	93	59
Total deferred exploratory well costs	**$ 783**	$ 470	$ 363
Number of projects with costs capitalized greater than one year after completion of drilling	**3**	3	2

Exploratory well costs capitalized greater than one year after completion of drilling as of December 31, 2007 included $46 million for the Ozona prospect in the Gulf of Mexico that was primarily incurred in 2001 and 2002, $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.

Marathon is continuing to evaluate options to develop the Ozona Prospect. Commercial terms have been secured that will allow this sub-sea well to be tied back to existing oil and natural gas infrastructure. We are actively searching for a rig to drill the planned development well.

The Equatorial Guinea discovery wells are part of Marathon s long-term LNG strategy. These discoveries will be developed when the natural gas supply from the nearby Alba Field starts to decline or additional LNG markets are entered that require increased natural gas supply.

Marathon and its partners are focused on subsurface evaluation and assessing development concepts for the Gudrun field with concept selection expected in 2008.

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

(In millions)	Balance at Beginning of Period	Additions	Dry Well Expense	Transfer to Proved Properties	Disposals	Balance at End of Period
Year ended December 31, 2007	**$ 470**	**$ 394**	**$ (39)**	**$ (42)**	**$**	**$ 783**
Year ended December 31, 2006	363	174	(27)	(21)	(19)	470
Year ended December 31, 2005	339	135	(31)	(80)		363

15. Goodwill

The changes in the carrying amount of goodwill for the years ended December 31, 2007 and 2006 were as follows:

(In millions)	E&P	OSM	RM&T[(a)]	Total
Balance as of December 31, 2005	$ 546	$	$ 761	$ 1,307
Adjustments to previously acquired goodwill	(6)		118	112
Disposals[(b)]	(21)			(21)
Balance as of December 31, 2006	519		879	1,398

Adjustments to previously acquired goodwill			**(7)**	**(7)**
Goodwill acquired	**71**	**1,437**		**1,508**
Balance as of December 31, 2007	**$ 590**	**$ 1,437**	**$ 872**	**$ 2,899**

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

(b) E&P segment goodwill allocated to the Russian businesses that were sold in June 2006 as discussed in Note 7.

The E&P segment tests goodwill for impairment in the second quarter of each year. The RM&T segment tests goodwill for impairment in the fourth quarter of each year. No impairment in the carrying value of goodwill has been identified. The goodwill in the OSM segment was acquired in October 2007; therefore no impairment test was performed in 2007.

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16. Intangible Assets

Intangible assets were as follows:

(In millions) December 31	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
2007			
Amortized intangible assets:			
Oil sands mining technology	**$ 105**	**$**	**$ 105**
Branding agreements	**58**	**22**	**36**
Elba Island delivery rights	**42**	**10**	**32**
Other	**107**	**48**	**59**
	$ 312	**$ 80**	**$ 232**
Unamortized intangible assets:			
Retail marketing tradenames	**$ 49**	**$**	**$ 49**
Other	**7**		**7**
	$ 56	**$**	**$ 56**
Total	**$ 368**	**$ 80**	**$ 288**
2006			
Amortized intangible assets:			
Branding agreements	$ 54	$ 20	$ 34
Elba Island delivery rights	42	8	34
Other	103	47	56
	$ 199	$ 75	$ 124
Unamortized intangible assets:			
Retail marketing tradenames	$ 49	$	$ 49
Other	7		7
	$ 56	$	$ 56
Total	$ 255	$ 75	$ 180

Amortization expense related to intangibles during 2007, 2006 and 2005 totaled $15 million, $19 million and $16 million. Estimated amortization expense for the years 2008-2012 is $19 million, $18 million, $16 million, $16 million and $15 million.

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17. Derivative Instruments

Derivative instruments are recorded at fair value. The fair value of exchange-traded commodity contracts is based on market quotes derived from major exchanges. The fair value for over-the-counter (OTC) commodity contracts is determined using option-pricing models or dealer quotes. The fair value of interest rate swaps and foreign currency forward contracts is based on dealer quotes. Marathon s consolidated balance sheet is reported on a net basis by brokerage firm, as permitted by master netting agreements.

The following table sets forth quantitative information by category of derivative instrument at December 31, 2007 and 2006. These amounts are reported on a gross basis by individual derivative instrument.

		2007		2006	
(In millions)	December 31	**Assets**	**(Liabilities)**	Assets	(Liabilities)
Commodity Instruments					
Fair value hedges:[(a)]					
Exchange-traded commodity futures		**$**	**$**	$	$ (4)
OTC commodity swaps		**10**	**(5)**	20	(15)
Non-hedge designation:					
Exchange-traded commodity futures		**$ 608**	**$ (692)**	$ 301	$ (258)
Exchange-traded commodity options		**313**	**(288)**	88	(93)
OTC commodity swaps		**17**	**(26)**	44	(34)
OTC commodity options			**(136)**	2	(1)
Nontraditional Instruments					
Long-term U.K. natural gas contracts[(b)]		**$**	**$ (291)**	$	$ (60)
Physical commodity contracts[(c)]		**271**	**(198)**	46	(64)
Financial Instruments					
Fair value hedges:					
OTC interest rate swaps[(d)]		**$**	**$ (3)**	$	$ (22)
Cash flow hedges: (e)					
OTC foreign currency forwards		**$ 12**	**$**	$ 3	$

(a) There was no ineffectiveness associated with fair value hedges for 2007 or 2006 because the hedging instruments and the existing firm commitment contracts are priced on the same underlying index. Derivative instruments used in the fair value hedges mature in 2008.

(b) The contract price under the long-term 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 twelve 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 for the next 18 months. The 18-month period represents approximately 90 percent of market liquidity in that region.

(c) Certain physical commodity contracts are classified as nontraditional derivative instruments because certain volumes covered by these contracts are physically netted at particular delivery locations. The netting process causes all contracts at such delivery locations to be considered derivative instruments. Other physical contracts that management has chosen not to designate as normal purchases or normal sales, which can include contracts that involve flash title, are also accounted for as nontraditional derivative instruments.

(d) The fair value of OTC interest rate swaps excludes accrued interest amounts not yet settled. As of December 31, 2007 and 2006, accrued interest was $3 million and $4 million. The net fair value of the OTC interest rate swaps as of December 31, 2007 and 2006 is included in long-term debt. See Note 20.

(e) The changes in fair value of cash flow hedges included no ineffectiveness during 2007 and ineffectiveness of $3 million during 2006 on a pretax basis.

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18. Fair Value of Financial Instruments

The following table summarizes financial instruments, excluding the derivative financial instruments in Note 17, by individual balance sheet line item at December 31, 2007 and 2006.

		2007		2006	
(In millions)	December 31	**Fair Value**	**Carrying Amount**	Fair Value	Carrying Amount
Financial assets:					
Cash and cash equivalents		**$ 1,199**	**$ 1,199**	$ 2,585	$ 2,585
Receivables		**5,897**			