MARATHON OIL CORP
Form 10-K
March 01, 2007

Use these links to rapidly review the document

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, 2006

Commission file number 1-5153

Marathon Oil Corporation

(Exact name of registrant as specified in its charter)

Delaware
(State of Incorporation)

25-0996816
(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
Common Stock, par value $1.00

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 o

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 o 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 o

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. o

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

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

The aggregate market value of Common Stock held by non-affiliates as of June 30, 2006: $29.924 billion. This amount is based on the closing price of the registrant's Common Stock on the New York Stock Exchange composite tape 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 345,862,952 shares of Marathon Oil Corporation Common Stock outstanding as of January 31, 2007.

Documents Incorporated By Reference:

Portions of the registrant's proxy statement relating to its 2007 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.

---

*

The Common Stock is listed on the New York Stock Exchange and the Chicago Stock Exchange.

MARATHON OIL CORPORATION

Unless the context otherwise indicates, references in this Annual Report on Form 10-K to "Marathon," "we," "our," or "us" are references to Marathon Oil Corporation, including its wholly-owned and majority-owned subsidiaries, and its ownership interests in equity method investees (corporate entities, partnerships, limited liability companies and other ventures over which Marathon exerts significant influence by virtue of its ownership interest, typically between 20 and 50 percent). Effective September 1, 2005, subsequent to the acquisition discussed in Note 6 to the consolidated financial statements, Marathon Ashland Petroleum LLC changed its name to Marathon Petroleum Company LLC. References to Marathon Petroleum Company LLC ("MPC") are references to the entity formerly known as Marathon Ashland Petroleum LLC.

TABLE OF CONTENTS

Disclosures Regarding Forward-Looking Statements

This Annual Report on Form 10-K, particularly Item 1. Business, Item 1A. Risk Factors, Item 3. Legal Proceedings, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 7A. Quantitative and Qualitative Disclosures about Market Risk, includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These statements typically contain words such as "anticipate," "believe," "estimate," "expect," "forecast," "plan," "predict" "target," "project," "could," "may," "should," "would" or similar words, indicating that future outcomes are uncertain. In accordance with "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, that could cause future outcomes to differ materially from those set forth in the forward-looking statements.

Forward-looking statements in this Report may include, but are not limited to, levels of revenues, gross margins, income from operations, net income or earnings per share; levels of capital, exploration, environmental or maintenance expenditures; the success or timing of completion of ongoing or anticipated capital, exploration or maintenance projects; volumes of production, sales, throughput or shipments of liquid hydrocarbons, natural gas and refined products; levels of worldwide prices of liquid hydrocarbons, natural gas and refined products; levels of reserves, proved or otherwise, of liquid hydrocarbons and natural gas; 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; 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 since that date, Marathon has only one class of common stock authorized.

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 (the "Acquisition"), MAP is now wholly owned by Marathon and its name was changed to Marathon Petroleum Company LLC ("MPC") effective September 1, 2005.

Segment and Geographic Information

Our operations consist of three operating segments: 1) Exploration and Production ("E&P") explores for, produces and markets crude oil and natural gas on a worldwide basis; 2) Refining, Marketing and Transportation ("RM&T") refines, markets and transports crude oil and petroleum products, primarily in the Midwest, the upper Great Plains and southeastern United States; and 3) Integrated Gas ("IG") markets and transports products manufactured from natural gas, such as liquefied natural gas ("LNG") and methanol, on a worldwide basis, and 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.

2

Exploration and Production

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

We conduct exploration, development and production activities in ten countries, with a focus on international growth while continuing to maintain our position in the United States. Principal exploration activities were in the United States, Norway, Angola and Indonesia. Principal development and production activities were in the United States, the United Kingdom, Norway, Equatorial Guinea and Libya.

Our 2006 worldwide net liquid hydrocarbon sales from continuing operations averaged 223 thousand barrels per day ("mbpd"), an increase of 36 percent from 2005 levels. Our 2006 worldwide net natural gas sales, including natural gas acquired for injection and subsequent resale, averaged 847 million cubic feet per day ("mmcfd"), a decrease of 9 percent compared to 2005. In total, our 2006 worldwide net sales from continuing operations averaged 365 thousand barrels of oil equivalent ("mboe") per day, compared to 319 mboe per day in 2005. (For purposes of determining 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 2007, our worldwide net production available for sale is expected to average 390 to 425 mboe per day, excluding future acquisitions and dispositions.

The above projections of 2007 worldwide net liquid hydrocarbon and natural gas production available for sale volumes are forward-looking statements. Some factors that could potentially affect levels of production available for sale include pricing, supply and demand for petroleum products, the amount of capital available for exploration and development, regulatory constraints, production decline rates of mature fields, timing of commencing production from new wells, drilling rig availability, inability to 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 2006, we drilled 33 gross (16 net) exploratory wells of which 21 gross (10 net) wells encountered commercial quantities of hydrocarbons. Of these 21 wells, 6 gross (4 net) wells were temporarily suspended or were in the process of completing at year end. Internationally, we drilled 21 gross (4 net) exploratory wells of which 16 gross (3 net) wells encountered commercial quantities of hydrocarbons. Of these 16 wells, 9 gross (3 net) wells were temporarily suspended or were in the process of being completed at December 31, 2006.

United States The Gulf of Mexico continues to be a core area for us. At the end of 2006, we had interests in 129 blocks in the Gulf of Mexico, including 100 in the deepwater area.

During 2006, we increased our interest from 20 percent to 30 percent in the Stones prospect (Walker Ridge Block 508). An appraisal well is planned for 2007 on this outside-operated 2005 discovery.

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, one of which was successful. 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.

A well on the Flathead prospect (Walker Ridge Block 30) in the Gulf of Mexico was suspended in 2002. Technical evaluations are complete and commercial evaluations continued in 2006. The drilling of this prospect is delayed due to the shortage of available deepwater rigs. We continue to pursue partnering opportunities with other oil and gas companies that have deepwater rigs under contract. We hold a 100 percent operated interest in the Flathead prospect.

Norway We hold interests in over 700,000 gross acres offshore Norway and plan to continue our exploration effort there. In 2006, we participated in a successful appraisal well on the Gudrun field, located 120 miles off the coast. Marathon holds a 28 percent outside-operated interest in Gudrun where we are primarily focused on evaluating development scenarios.

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 2007, we have announced 20 discoveries on these blocks. We have

also participated in four wells that have reached total depth, the results of which will be announced upon government and partner approvals. We expect to participate in 10 or 11 wells on these blocks in 2007.

On Block 31, four previously announced discoveries (Plutao, Saturno, Marte and Venus) and one successful appraisal well form a planned development area in the northeastern portion of the block. Also on Block 31, we had five previously announced discoveries located in the southeastern portion of the block (Palas, Ceres, Juno, Astraea and Hebe). In 2006 and early 2007, we announced discoveries at Urano, Titania, Terra and an unnamed well. We are integrating the results of these wells with our previously announced discoveries.

On Block 32, we previously announced three discoveries (Gindungo, Canela and Gengibre). In 2006, we announced the fourth discovery on Block 32, the Mostarda-1, and a successful deepwater delineation well, Gengibre-2. We also announced that hydrocarbons were encountered in the Salsa well, but additional drilling is required to assess its commerciality. In early 2007, we announced two additional discoveries, the Manjericao and Caril wells. These discoveries move Block 32 closer toward establishment of a commercial development.

Equatorial Guinea During 2004, we participated in two natural gas and condensate discoveries on the Alba Block offshore Equatorial Guinea. The Deep Luba discovery well, drilled from the Alba field production platform, encountered natural gas and condensate in several pay zones. The Gardenia discovery well is located 11 miles southwest of the Alba Field. We are currently evaluating development scenarios for both the Deep Luba and Gardenia discoveries. We hold a 63 percent operated interest in the Alba Block.

In 2004, we announced the results of the Corona well drilled on Block D offshore Equatorial Guinea, where we are the operator with a 90 percent working interest. The Corona well confirmed an extension of the Alba field on to Block D. An application for an Area of Commercial Discovery was submitted prior to the end of the production sharing contract's exploration period, which expired at the end of 2006. We are currently in discussions with the Equatorial Guinea government regarding our rights to develop the Block D extension of the Alba Field.

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 2006 included the drilling of 12 wells, nine of which were successful. Most of these discoveries extended previously defined hydrocarbon accumulations.

Canada We are the operator and own a 30 percent interest in the Annapolis lease offshore Nova Scotia, where we continue to evaluate further drilling. In late 2006, we decided to withdraw from the adjacent Cortland lease, where we hold a 75 percent interest, and the adjacent Empire lease, where we hold a 50 percent interest. As a result of this withdrawal, a charge equal to 25 percent of the remaining work commitment, or $47 million, was recorded as exploration expense in 2006 and the cash payment will be due to the Canadian provincial government in 2007.

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 oil and natural gas production region. The production sharing contract with the Indonesian government was signed in 2006. We expect to begin collecting geophysical data in 2007, followed by exploratory drilling in 2008 and 2009.

Production (including development activities)

United States Our U.S. operation accounted for 34 percent of our 2006 worldwide net liquid hydrocarbon sales from continuing operations and 63 percent of our worldwide net natural gas sales.

During 2006, our net sales in the Gulf of Mexico averaged 35 mbpd of liquid hydrocarbons, representing 46 percent of our total U.S. net liquid hydrocarbon sales, and 43 mmcfd of natural gas, representing 8 percent of our total U.S. net natural gas sales. Net liquid hydrocarbon sales in the Gulf of Mexico increased slightly from the prior year, mainly due to the effects of five tropical storms/hurricanes in 2005. Net natural gas sales decreased by 41 mmcfd from the prior year primarily because natural gas sales from the Camden Hills field ended in early 2006 as a result of increased water production. At year-end 2006, we held interests in seven producing fields and eight platforms in the Gulf of Mexico, of which four platforms are operated by Marathon.

The majority of our sales in the Gulf of Mexico comes from the Petronius development in Viosca Knoll Blocks 786 and 830. We own a 50 percent outside-operated interest in these blocks. The 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 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 initial 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 2006 with first production expected in early 2008.

We are one of the largest natural gas producers in the Cook Inlet and adjacent Kenai Peninsula of Alaska. In 2006, our Alaskan net natural gas sales averaged 156 mmcfd, representing 29 percent of our total U.S. net natural gas sales. 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. In May 2006, upon receipt of regulatory approvals, we began to produce and store natural gas in a partially depleted reservoir in the Kenai natural gas field. The natural gas in storage will be used to manage supplies to meet contractual demand. In addition to our operations in other established Alaskan fields, production from the Ninilchik field began in 2003 and development continues on the field. Ninilchik natural gas is transported through the 35-mile portion of the Kenai Kachemak Pipeline which connects Ninilchik to the existing natural gas pipeline infrastructure serving residential, utility and industrial markets on the Kenai Peninsula, in Anchorage and in other parts of south central Alaska. We operate Ninilchik and own a 60 percent interest in it and the section of the Kenai Kachemak Pipeline described above. Our 2006 development program in the Cook Inlet included participation in the drilling of seven wells.

Net liquid hydrocarbon sales from our Wyoming fields averaged 21 mbpd in 2006 and 2005. Net natural gas sales from our Wyoming fields averaged 119 mmcfd in 2006 compared to 107 mmcfd in 2005. The increase in our Wyoming net natural gas sales is primarily attributed to higher net sales from the Powder River Basin, which averaged 77 mmcfd in 2006 compared to 66 mmcfd in 2005 as a result of 2005 drilling activity. Development of the Powder River Basin continued in 2006 with 119 wells drilled, which was down from the 195 wells drilled in 2005 due to project delays primarily caused by regulatory and produced water management issues. Additional development of our southwest Wyoming interests continued in 2006 where we participated in the drilling of 27 wells.

Net natural gas sales from our Oklahoma fields averaged 87 mmcfd in 2006 compared to 77 mmcfd in 2005 primarily as a result of development and exploratory drilling. Our 2006 development program continued to focus in the Anadarko Basin where we participated in the drilling of 75 wells.

Net natural gas sales from our east Texas and north Louisiana fields averaged 71 mmcfd in 2006 compared to 75 mmcfd in 2005. This decrease is primarily attributable to sour gas handling capacity limits at the natural gas plants that purchase our east Texas natural gas, partially offset by development drilling results. Active development of the Mimms Creek field in east Texas continued in 2006.

Net liquid hydrocarbon sales from the Permian Basin region, which extends from southeast New Mexico to west Texas, averaged 14 mbpd in 2006 compared to 16 mbpd in 2005. This decrease in net sales was due to natural field declines partially offset by development project results in the Indian Basin and Drinkard areas of southeast New Mexico.

In the first half of 2006, we completed leasehold acquisitions totaling approximately 200,000 acres in the Bakken Shale oil play. The majority of the acreage is located in North Dakota with the remainder in eastern Montana. We now own a substantial position in the Bakken Shale with approximately 300 locations to be drilled over the next five years. Our initial focus has been to evaluate our leasehold position.

In July 2006, we completed a natural gas leasehold acquisition 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 over the next ten years with first production expected in late 2007.

We continue to assess our acreage position in the Barnett Shale gas play in north central Texas. To date, we have leased approximately 85,000 net acres in two counties. One core well and five horizontal wells have been drilled and completion activity is underway on these first wells. Seismic data was acquired in 2006 and is being evaluated.

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 interest in the South, Central, North and West Brae fields and a 38 percent 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 are gas condensate fields. Our share of sales from the Brae area averaged 15 mbpd of liquid hydrocarbons in 2006, compared with 18 mbpd in 2005. This reduction primarily resulted from West Brae field decline and the timing of sales of liquid hydrocarbons. Our share of Brae natural gas sales averaged 151 mmcfd, which was lower than the 169 mmcfd in 2005 as a result of natural field declines in the North and East Brae 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, there are 28 third-party fields 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 gas from the Brae and the third-party Beryl areas 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 third-party Britannia field.

In the U.K. Atlantic Margin, we own an approximate 30 percent interest in the outside-operated Foinaven area complex, consisting of a 28 percent interest in the main Foinaven field, 47 percent of East Foinaven and 20 percent of the T35 and T25 accumulations. Our share of sales from the Foinaven fields averaged 17 mbpd of liquid hydrocarbons and 10 mmcfd of natural gas in 2006, compared to 16 mbpd and 9 mmcfd in 2005, primarily as a result of increased liquid handling capacity following facility modifications, increased well potential and improved operating efficiency.

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

During 2006, net liquid hydrocarbon and natural gas sales in Norway from the Heimdal, Vale and Skirne fields averaged 2 mbpd and 36 mmcfd. We own a 24 percent outside-operated interest in the Heimdal field, a 47 percent outside-operated interest in the Vale field and a 20 percent outside-operated interest in the Skirne field.

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 interest, and the Boa discovery, in which we have a 58 percent interest. During 2004, we received approval from the Norwegian authorities for our Alvheim plan for development and operation ("PDO"), which will consist of a floating production, storage and offloading vessel ("FPSO") with subsea infrastructure for five drill centers and associated flow lines. The PDO also outlines transportation of produced oil by shuttle tanker and transportation of produced natural gas to the SAGE system using a new 14-inch, 24-mile cross border pipeline. Marathon and its Alvheim project partners acquired the Odin multipurpose shuttle tanker early in 2005. The vessel is currently being modified to serve as an FPSO and has been renamed "Alvheim." In 2004, the Alvheim partners reached agreement to tie-in the nearby Vilje discovery, in which we own a 47 percent outside-operated interest, subject to the approval of the Norwegian government. In 2005, the Norwegian government approved the Vilje PDO. Progress also continues on the Vilje project, where the subsea preparation is 98 percent complete and development drilling is expected to commence in the second quarter of 2007. First production from the Alvheim/Vilje development is expected during the second quarter of 2007. Four wells will be available at first production and drilling activities will continue into 2008. A peak net rate of approximately 75,000 boepd is expected in early 2008.

In 2006, we submitted a PDO for the Volund field to the Norwegian government, with a recommendation that the field be developed as a subsea tie-back to the Alvheim FPSO. In December 2006, the Ministry of Petroleum and Energy forwarded the PDO to the Norwegian King in Council for approval. Approval was received in early 2007. The Volund development will include three producing wells and a water injection well. The crude oil production 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 interest and serve as operator, is expected to begin production in the second quarter of 2009.

Ireland We own a 100 percent interest in the Kinsale Head, Ballycotton and Southwest Kinsale fields in the Celtic Sea offshore Ireland. In February 2006, we acquired an 87 percent operated interest in the Seven Heads natural gas field. Previously, we processed and transported natural gas and we provided field operating services to the Seven Heads group through our existing Kinsale Head facilities. Net natural gas sales in Ireland were 46 mmcfd in 2006, compared with 50 mmcfd in 2005. 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. In 2006, we began to produce and hold in storage natural gas from the Kinsale Head field for future delivery under a contract that expires in March 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 interest in the outside-operated Corrib natural gas development project, located 40 miles off Ireland's northwest coast, where five of the seven wells necessary to develop the field have been drilled. During 2004, An Bord Pleanála (the Planning Board) upheld the Mayo County Council's decision to grant planning approval for the proposed natural gas terminal at Bellanaboy Bridge, County Mayo, which will process natural gas from the Corrib field. Development activities started in late 2004 but were suspended to facilitate dialogue and clarification of issues raised by opponents of the project. In July 2006, the partners in this project accepted the findings of a government-commissioned independent safety review and the report of an independent mediator regarding the onshore pipeline associated with the proposed development. The onshore pipeline will be re-routed and routing studies are underway. Construction of the natural gas plant re-commenced in the third quarter of 2006. First production from the field is expected in 2009.

Equatorial Guinea We own a 63 percent operated 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 2006, net liquid hydrocarbon sales averaged 48 mbpd and net natural gas sales averaged 68 mmcfd, compared to 40 mbpd and 92 mmcfd in 2005. A condensate expansion project ramped up to full production and a new, larger LPG plant was completed in 2005. Net sales in 2006 averaged 36 mbpd of condensate and 12 mbpd of LPG.

We own 45 percent of Atlantic Methanol Production Company LLC ("AMPCO"), the results of which are included in the Integrated Gas segment. In 2006, we supplied a gross 99 mmcfd of dry gas, which remains after the condensate and LPG are removed, to AMPCO, where it was used to manufacture methanol. Remaining dry gas is returned offshore and reinjected into the Alba reservoir for later production when the LNG production facility on Bioko Island, discussed below under Integrated Gas, is completed.

Libya Net liquid hydrocarbon sales in Libya averaged 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 2006 sales in Libya represented 37 percent of our international liquid hydrocarbon sales from continuing operations. We continue to work with our partners to define and implement growth plans for this business.

Gabon We are the operator of the Tchatamba South, Tchatamba West and Tchatamba Marin fields offshore Gabon with a 56 percent interest. Net sales in Gabon averaged 10 mbpd of liquid hydrocarbons in 2006, compared with 12 mbpd in 2005. Production from these three fields is processed on a single offshore facility at Tchatamba Marin, with processed oil being transported through an offshore and onshore pipeline to an outside-operated storage facility.

Russia During 2003 we acquired Khanty Mansiysk Oil Corporation which operated oil fields located in the Khanty Mansiysk region of western Siberia. Net liquid hydrocarbon sales were primarily from the East Kamennoye and Potenay fields. In June 2006, we sold these Russian oil exploration and production businesses.

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 and will not consider resuming any activity regarding our interests there until such time as it is permitted under U.S. law. Our intention is to exit this license in 2007.

We discovered the Ash Shaer and Cherrife 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 July 2006, the new production sharing contract awarded by the Syrian government was signed into law. This contract gave us the right to assign all or part of our interest in these fields to a third party, subject to the consent of the Syrian government, and also resolved the previous disputes between us, the Syrian Petroleum Company and the Syrian government over our interest in these fields. In October 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. While we continue to hold a 10 percent outside-operated interest, we continue to comply with all U.S. sanctions related to Syria. We expect to sell the remaining 10 percent interest in 2007.

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 and Blocks 31 and 32 offshore Angola, the timing of production from the Neptune development, the Piceance Basin, 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 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 and Blocks 31 and 32 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.

Reserves

At December 31, 2006, our net proved liquid hydrocarbon and natural gas reserves totaled 1.262 billion boe, of which approximately 40 percent were located in Organization for Economic Cooperation and Development ("OECD") countries. The following table sets forth estimated quantities of net proved oil 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		
	2006	**2005**	**2004**	**2006**	**2005**	**2004**
Liquid Hydrocarbons *(Millions of barrels)*						
United States	**150**	165	171	**172**	189	191
Europe	**35**	39	41	**108**	98	107
Africa	**381**	368	147	**397**	373	223
Worldwide Continuing Operations	**566**	572	359	**677**	660	521
Discontinued Operations [(a)]		31	27		44	39
WORLDWIDE	**566**	603	386	**677**	704	560
Developed reserves as a percent of total net proved reserves	**84%**	86%	69%			
Natural Gas *(Billions of cubic feet)*						
United States	**857**	943	992	**1,069**	1,209	1,364
Europe	**238**	326	376	**444**	486	544
Africa	**648**	638	570	**1,997**	1,852	1,564
WORLDWIDE	**1,743**	1,907	1,938	**3,510**	3,547	3,472
Developed reserves as a percent of total net proved reserves	**50%**	54%	56%			
Total BOE *(Millions of barrels)*						
United States	**293**	322	336	**350**	390	418
Europe	**75**	93	104	**182**	179	198
Africa	**489**	475	242	**730**	682	484
Worldwide Continuing Operations	**857**	890	682	**1,262**	1,251	1,100
Discontinued Operations [(a)]		31	27		44	39
WORLDWIDE	**857**	921	709	**1,262**	1,295	1,139
Developed reserves as a percent of total net proved reserves	**68%**	71%	62%			

(a) Represents Marathon's Russian businesses, which were sold in 2006.

Proved developed reserves represented 68 percent of total proved reserves as of December 31, 2006, as compared to 71 percent as of December 31, 2005. Of the 405 million boe of proved undeveloped reserves at year-end 2006, less than 10 percent of the volume is associated with projects that have been included in proved reserves for more than three years while 11 percent of the proved undeveloped reserves were added during 2006.

During 2006, we added a total of 146 million boe of net proved reserves, principally in Libya and Equatorial Guinea. We disposed of 45 million boe, while producing 134 million boe. Of the total net proved reserve additions, 82 million boe were proved developed and 64 million boe were proved undeveloped reserves. During 2006, we transferred 18 million boe from proved undeveloped to proved developed reserves. Costs incurred for the periods ended December 31, 2006, 2005 and 2004 relating to the development of proved undeveloped oil and natural gas reserves, were $1.010 billion, $955 million and $708 million. As of December 31, 2006, estimated future development costs relating to the development of proved undeveloped oil and natural gas reserves for the years 2007 through 2009 are projected to be $466 million, $348 million and $231 million.

Our Libyan fields had the most significant positive changes, totaling 69 million boe. This included positive revisions due to access to additional data and our improved understanding of reservoir performance during the first year after our re-entry and additions for future development drilling. At the end of 2006, our proved reserves associated with Libya totaled 214 million boe, or 17 percent of our total proved reserves. Additionally, 21 million boe were added to our proved reserves for the Alba field in Equatorial Guinea, primarily as a result of expanded natural gas marketing and supply agreements.

The above estimated quantities of net proved oil and natural gas reserves and estimated future development costs relating to the development of proved undeveloped oil 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 reserve estimation process, see Management's Discussion and Analysis of Financial Condition and Results of Operations   Critical Accounting Estimates   Estimated Net Recoverable Quantities of Oil and Natural Gas, 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 on pages F-46 through F-47. We filed reports with the U.S. Department of Energy ("DOE") for the years 2005 and 2004 disclosing the year-end estimated oil and natural gas reserves. We will file a similar report for 2006. The year-end estimates reported to the DOE are the same as the estimates reported in the Supplementary Information on Oil and Gas Producing Activities.

Delivery Commitments

We have committed to deliver fixed and determinable quantities of natural gas to customers under a variety of contractual arrangements.

In Alaska, we have two long-term sales contracts with local utility companies, which obligate us to supply 124 bcf of natural gas over the remaining lives of these contracts, which terminate in 2012 and 2018. In addition, we own a 30 percent interest in a Kenai, Alaska LNG plant and a proportionate share of the long-term LNG sales obligation to two Japanese utility companies. This obligation is estimated to total 43 bcf through the remaining life of the contract, which terminates in 2009. These commitments are structured with variable-pricing terms. Our production from various natural gas fields in the Cook Inlet supply the natural gas to service these contracts. Our proved reserves in the Cook Inlet are sufficient to meet these contractual obligations.

In the U.K., we have two long-term sales contracts with utility companies, which obligate us to supply 125 bcf of natural gas through the remaining lives of these contracts, which terminate in 2009. Our Brae area proved reserves, acquired natural gas contracts and estimated production rates are sufficient to meet these contractual obligations. Pricing under these natural gas sales contracts is variable. See Note 18 to the consolidated financial statements for further discussion of these contracts.

Oil and Natural Gas Net Sales

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

Net Liquid Hydrocarbon Sales[a]

(Thousands of barrels per day)

	2006	2005	2004
United States[b]	**76**	76	81
Europe[c]	**35**	36	40
Africa[c]	**112**	52	32
Worldwide Continuing Operations	**223**	164	153
Discontinued Operations[d]	**12**	27	17
WORLDWIDE	**235**	191	170

Net Natural Gas Sales[e]

(Millions of cubic feet per day)

	2006	2005	2004
United States[b]	**532**	578	631
Europe[f]	**197**	224	273
Africa	**72**	92	76
WORLDWIDE	**801**	894	980

(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 46 mmcfd, 38 mmcfd and 19 mmcfd in 2006, 2005 and 2004.

Productive and Drilling Wells

The following tables set forth productive wells and service wells as of December 31, 2006, 2005 and 2004, and drilling wells as of December 31, 2006.

Gross and Net Wells

	Productive Wells[(a)]				Service Wells[(b)]		Drilling Wells[(c)]	
	Oil		Natural Gas					
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
2006								
United States	**5,661**	**2,068**	**5,554**	**4,063**	**2,729**	**834**	**39**	**21**
Europe	**51**	**19**	**75**	**41**	**31**	**12**	**2**	**1**
Africa	**925**	**155**	**13**	**9**	**100**	**19**	**10**	**2**
Other International								
WORLDWIDE	**6,637**	**2,242**	**5,642**	**4,113**	**2,860**	**865**	**51**	**24**
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		
2004								
United States	5,604	2,022	4,860	3,702	2,749	845		
Europe	54	20	66	35	28	10		
Africa	9	5	13	9	3	1		
Other International	116	116			23	23		
WORLDWIDE	5,783	2,163	4,939	3,746	2,803	879		

(a) Includes active wells and wells temporarily shut-in. Of the gross productive wells, wells with multiple completions operated by Marathon totaled 294, 278 and 273 in 2006, 2005 and 2004. Information on wells with multiple completions operated by others is unavailable to us.

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

(c) Consists of exploratory and development wells.

Drilling Activity

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

Net Productive and Dry Wells Completed[(a)]

		2006	2005	2004
United States				
Development[(b)]	- Oil	**32**	46	13
	- Natural Gas	**186**	288	167
	- Dry	**5**	4	
	Total	**223**	338	180
Exploratory	- Oil	**3**	2	1
	- Natural Gas	**8**	17	8
	- Dry	**3**	2	6
	Total	**14**	21	15
	Total United States	**237**	359	195
International				
Development[(b)]	- Oil	**51**	68	27
	- Natural Gas	**1**	2	3
	- Dry		1	1
	Total	**52**	71	31
Exploratory	- Oil	**19**	2	2
	- Natural Gas			
	- Dry	**6**	4	7
	Total	**25**	6	9
	Total International	**77**	77	40
	WORLDWIDE	**314**	436	235

(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.

Oil and Natural Gas Acreage

The following table sets forth, by geographic area, the developed and undeveloped oil and natural gas acreage that we held as of December 31, 2006.

Gross and Net Acreage

	Developed	Undeveloped	Developed and Undeveloped

(Thousands of Acres)	Developed		Undeveloped		Developed and Undeveloped	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
United States	1,183	733	2,813	1,366	3,996	2,099
Europe	467	367	972	401	1,439	768
Africa	12,977	2,150	2,901	745	15,878	2,895
Other International			2,577	1,684	2,577	1,684
WORLDWIDE	14,627	3,250	9,263	4,196	23,890	7,446

Refining, Marketing and Transportation

Our RM&T operations are primarily conducted by MPC and its subsidiaries, including its wholly-owned subsidiaries Speedway SuperAmerica LLC ("SSA") and Marathon Pipe Line LLC.

Refining

We own and operate seven refineries with an aggregate refining capacity of 974 mbpd of crude oil. During 2006, our refineries processed 980 mbpd of crude oil and 234 mbpd of other charge and blend stocks for a crude oil capacity utilization rate of 101 percent. The table below sets forth the location and daily throughput capacity of each of our refineries as of December 31, 2006.

Crude Oil Refining Capacity *(Thousand Barrels per Day)*	
Garyville, Louisiana	245
Catlettsburg, Kentucky	222
Robinson, Illinois	192
Detroit, Michigan	100
Canton, Ohio	73
Texas City, Texas	72
St. Paul Park, Minnesota	70
TOTAL	974

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. 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 a major turnaround at our Catlettsburg refinery in 2006.

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

Refined Product Yields

(Thousands of Barrels per Day)

	2006	**2005**	**2004**
Gasoline	**661**	644	608
Distillates	**323**	318	299
Propane	**23**	21	22
Feedstocks and Special Products	**107**	96	94
Heavy Fuel Oil	**26**	28	25
Asphalt	**89**	85	77
TOTAL	**1,229**	1,192	1,125

We completed all of our ultra-low sulfur diesel fuel modifications required by the U.S. Environmental Protection Agency prior to its June 1, 2006 deadline. These modifications were completed on time and under budget.

In 2006, our Board of Directors approved a projected $3.2 billion expansion of our Garyville, Louisiana refinery by 180 mbpd to 425 mbpd, which will increase our total refining capacity to 1.154 million barrels per day ("mmbpd"). We recently received air permit approval from the Louisiana Department of Environmental Quality for this project and construction is expected to begin in mid-2007, with startup planned for the fourth quarter of 2009.

We have also commenced front-end engineering and design ("FEED") for a potential heavy oil upgrading project at our Detroit refinery, which would allow us to process increased volumes of Canadian oil sands production, and are undertaking a feasibility study for a similar upgrading project at our Catlettsburg refinery.

Marketing

We are a supplier of gasoline and distillates to resellers and consumers within our market area in the Midwest, the upper Great Plains and southeastern United States. In 2006, our refined product sales volumes (excluding matching buy/sell transactions) totaled 21.5 billion gallons, or 1.401 mmbpd. The average sales price of our refined products in aggregate was $77.76 per barrel for 2006. The following table sets forth our refined product sales by product group and our average sales price for each of the last three years.

Refined Product Sales

(Thousands of Barrels per Day)

	2006	2005	2004
Gasoline	**804**	836	807
Distillates	**375**	385	373
Propane	**23**	22	22
Feedstocks and Special Products	**106**	96	92
Heavy Fuel Oil	**26**	29	27
Asphalt	**91**	87	79
TOTAL[(a)]	**1,425**	1,455	1,400
Average sales price ($ per barrel)	**$ 77.76**	$ 66.42	$ 49.53

(a) Includes matching buy/sell volumes of 24 mbpd, 77 mbpd and 71 mbpd in 2006, 2005 and 2004. 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 product sales volumes for the remainder of 2006 than would have been reported under the 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 71 percent of our refined product sales volumes in 2006. We sold 52 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, the upper Great Plains and southeastern United States. Our customer base includes approximately 800 asphalt-paving contractors, government entities (states, counties, cities and townships) and asphalt roofing shingle manufacturers.

We blended 35 mbpd of ethanol into gasoline in 2006. In 2005 and 2004, we blended 35 mbpd and 30 mbpd of ethanol. The 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; and Milwaukee, Wisconsin, and we sell low-vapor-pressure gasoline in nine states.

As of December 31, 2006, we supplied petroleum products to about 4,200 Marathon branded retail outlets located primarily in Ohio, Michigan, Indiana, Kentucky and Illinois. Branded retail outlets are also located in Florida, Georgia, Minnesota, Wisconsin, West Virginia, Tennessee, Virginia, North Carolina, Pennsylvania, Alabama and South Carolina. Sales to Marathon brand jobbers and dealers accounted for 14 percent of our refined product sales volumes in 2006.

SSA sells gasoline and diesel fuel through company-operated retail outlets. Sales of refined products through these SSA retail outlets accounted for 15 percent of our refined product sales volumes in 2006. As of December 31, 2006, 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 $2.7 billion in 2006, compared with $2.5 billion in 2005. 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 60 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 269 locations in 37 states and Canada at December 31, 2006. In 2006, PTC expanded internationally with the opening of a site in Ontario, Canada. 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.

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 2006, U.S. sourced crude oil averaged 470 mbpd, or 48 percent of the crude oil processed at our refineries, including a net 14 mbpd from our production operations. In 2006, Canada was the source for 13 percent, or 130 mbpd of crude oil processed and other foreign sources supplied 39 percent, or 380 mbpd, of the crude oil processed by our refineries, including 198 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 for each of the last three years.

Sources of Crude Oil Refined

(Thousands of Barrels per Day)

	2006	**2005**	**2004**
United States	**470**	447	416
Canada	**130**	111	130
Middle East and Africa	**266**	301	276
Other International	**114**	114	117
TOTAL	**980**	973	939
Average cost of crude oil throughput ($ per barrel)	**$ 61.15**	$ 51.85	$ 39.16

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, 2006, we owned, leased, operated or held equity method investments in 68 miles of crude oil gathering lines, 3,718 miles of crude oil trunk lines and 3,855 miles of refined product 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

(In millions)

	2006	**2005**	**2004**
Crude oil gathering lines	**6**	7	7
Crude oil trunk lines	**542**	591	569
Refined products trunk lines	**402**	445	407
TOTAL	**950**	1,043	983

At December 31, 2006 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;
- 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 87 owned and operated light product and asphalt terminals are strategically located throughout the Midwest, upper Great Plains and Southeast. These facilities are supplied by a combination of pipelines, barges, rail cars and trucks. Our marine transportation operations include towboats (15 owned) and barges (180 owned, 4 leased) that transport refined products on the Ohio, Mississippi and Illinois rivers, their tributaries and the Intercoastal Waterway. We lease and own over 2,000 rail cars of various sizes and capacities for movement and storage of petroleum products and over 100 tractors and tank trailers.

Ethanol Production

In 2006, we signed a definitive agreement forming a 50/50 joint venture that will construct and operate one or more ethanol production plants. Our partner in the joint venture will provide the day-to-day management of the plants, as well as grain procurement, distillers dried grain marketing and ethanol management services. This venture will enable us to maintain the reliability of a portion of our future ethanol supplies. Together with our partner, we selected the venture's initial plant site, Greenville, Ohio, and construction has commenced on a 110 million gallon per year ethanol facility. The facility is expected to be operational as soon as the first quarter of 2008.

The above discussion of the RM&T segment includes forward-looking statements concerning the planned expansion of the Garyville refinery, potential heavy oil refining upgrading projects and a joint venture that would construct and operate ethanol plants. Some factors that could affect the Garyville expansion project and the ethanol plant construction, management and development include necessary government and third party approvals, transportation logistics, availability of materials and labor, unforeseen hazards such as weather conditions and other risks customarily associated with construction projects. The Garyville project may be further affected by crude oil supply. These factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements. Factors that could affect the heavy oil refining upgrading projects include unforeseen difficulty in negotiation of definitive agreements, results of front-end engineering and design work, approval of our Board of Directors, inability or delay in obtaining necessary government and third-party approvals, continued favorable investment climate, and other geological, operating and economic considerations.

Other

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 U.S. Environmental Protection Agency ("EPA") has published a proposed rule to implement the RFS, and we anticipate that a final rule will be published in mid-2007. Federal legislation may be proposed in 2007 which may require even greater quantities of renewable fuels. Marathon intends to comply with all regulations that are adopted.

Integrated Gas

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

Alaska LNG

We own a 30 percent interest in a Kenai, Alaska, natural gas liquefaction plant and 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, the LNG has been sold under a long-term contract with two of Japan's largest utility companies. This contract continues through March 2009, with 2006 LNG deliveries totaling 61 gross bcf (19 net bcf). In January 2007, along with our partner, we filed a request with the U.S. Department of Energy to extend the export license for this natural gas liquefaction plant through March 2011.

Equatorial Guinea LNG

In 2004, we and our partner, Compania Nacional de Petroleos de Guinea Ecuatorial (the National Oil Company of Equatorial Guinea or "GEPetrol"), through Equatorial Guinea LNG Holdings Limited ("EGHoldings"), began construction of a 3.7 million metric ton per annum ("mmtpa") LNG production facility on Bioko Island. We expect to begin delivering 3.4 mmtpa, or 460 mmcfd, during the second quarter of 2007 under a 17-year sales and purchase agreement. The purchaser under this agreement will take delivery of the LNG facility's production on an FOB Bioko Island basis with pricing linked principally to the Henry Hub index, regardless of destination. This project will allow us to monetize our natural gas reserves from the Alba field, as natural gas for the production facility will be purchased from the Alba field participants under a long-term natural gas supply agreement. We are currently seeking additional natural gas supplies to allow full utilization of this LNG facility, which is designed to have a higher capacity and a longer life than the current 17-year sales and purchase agreement.

In July 2005, Marathon and GEPetrol entered into agreements under which Mitsui & Co., Ltd. ("Mitsui") and a subsidiary of Marubeni Corporation ("Marubeni") acquired 8.5 percent and 6.5 percent interests in EGHoldings. In November 2006, GEPetrol transferred its 25 percent interest to Sociedad Nacional de Gas de Guinea Ecuatorial ("SONAGAS"), which is also controlled by the government of Equatorial Guinea. Following these transaction, we hold a 60 percent interest in EGHoldings, with SONAGAS holding a 25 percent interest and Mitsui and Marubeni holding the remaining interests.

In 2006, with our project partners, we awarded a FEED contract for initial work related to a potential second LNG production facility on Bioko Island, Equatorial Guinea. The FEED work is expected to be completed during 2007. The scope of the FEED work for the potential 4.4 mmtpa LNG project includes feed gas metering, liquefaction, refrigeration, ethylene storage, boil off gas compression, product transfer to storage and LNG product metering. A final investment decision is expected in early 2008.

Elba Island LNG

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

We own a 45 percent interest in AMPCO, which owns a methanol plant located in Malabo, Equatorial Guinea. Feedstock for the plant is supplied from our natural gas production in the Alba field. Methanol sales totaled 733,680 gross metric tons (330,156 net metric tons) in 2006. Production from the plant is used to supply customers in Europe and the United States.

Gas Technology

We invest in natural gas technology research, including gas-to-liquids ("GTL") technology which offers the ability to convert natural gas into premium fuels. In addition to GTL, we continue to evaluate application of gas technologies accessible through licenses, including methanol-to-power and compressed natural gas. We also continue to develop a proprietary gas-to-fuels ("GTF") technology, which can be configured to convert natural gas resources into premium fuels.

The above discussion of the integrated gas segment contains forward looking statements with respect to the timing and levels of production associated with the LNG production facility and the possible expansion thereof. Factors that could affect the LNG production facility include unforeseen problems arising from commissioning of the facilities, unforeseen hazards such as weather conditions and other operating considerations such as shipping the LNG. In addition to these factors, other factors that could potentially affect the possible expansion of the current LNG production facility and the development of additional LNG capacity through additional projects include partner approvals, access to sufficient natural gas volumes through exploration or commercial negotiations with other resource owners and access to sufficient regasification capacity. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Competition and Market Conditions

Strong competition exists in all sectors of the oil and gas industry and, in particular, in the exploration 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 currently rank ninth among U.S.-based petroleum companies on the basis of 2005 worldwide liquid hydrocarbon and natural gas production.

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, 2006. 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 70 companies in the sale of petroleum products in the spot market; nine refiner/marketers in the supply of branded petroleum products to dealers and jobbers; and approximately 260 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 crude oil, natural gas and petroleum products, as well as changes in competitive conditions in the markets we serve. Generally, results from production operations benefit from higher crude oil and natural gas 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.

18

Financial Matters Agreement

Under the financial matters agreement, United States Steel has assumed and agreed to discharge all of Marathon's 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 Marathon:

- 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 the lease term extending to 2012, subject to extensions;
- obligations relating to various lease arrangements accounted for as operating leases and various guarantee arrangements, all of which were assumed by United States Steel; and
- certain other guarantees.

The financial matters agreement also provides that, on or before the tenth anniversary of the Separation, United States Steel will provide for Marathon's 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 Marathon 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 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 lease obligations without the prior consent of Marathon other than extensions set forth in the terms of the assumed leases, other than extensions set forth in the terms of any of the assumed leases.

The financial matters agreement also requires United States Steel to use commercially reasonable efforts to have Marathon released from its obligations under a guarantee Marathon 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 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 the payments on the assumed obligations. The agreement also obligates Marathon 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 Marathon under the financial matters agreement are general unsecured obligations that rank equal to United States Steel's accounts payable and other general unsecured obligations. The financial matters agreement does not contain any financial covenants and United States Steel is free to incur additional debt, grant mortgages on or security interests in its property and sell or transfer assets without our consent.

Tax Sharing Agreement

Marathon and United States Steel have a tax sharing agreement that applies to each of their consolidated tax reporting groups. During 2006, the Internal Revenue Service completed its review of all federal income tax returns filed by USX Corporation for taxable periods ending on or prior to the date of the Separation. Marathon and United States Steel have settled all matters related to federal income taxes under this agreement. Remaining matters related to state and local income taxes are not expected to have any significant effect on Marathon.

Obligations Associated with the Separation as of December 31, 2006

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 Corporate Governance and Nominating Committee of our Board of Directors is responsible for overseeing our position on public issues identified by management, 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 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. Other climate change legislation and regulations both in the United States and abroad are in various stages of development. Although there may be financial impact (including compliance costs) associated with any legislation or regulation, the extent and magnitude of impact cannot be reliably or accurately estimated due to the present uncertainty of these measures. 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 subject to numerous 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 cleanup on any responsible party without regard to negligence or fault and impose liability on us for the conduct of others or conditions others have caused, or for our acts that complied with all applicable requirements when we performed them. 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 standards 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 "Management's Discussion and Analysis of Environmental Matters, Litigation and Contingencies" and "Legal Proceedings."

Air

Of particular significance to our refining operations were U.S. EPA regulations that required reduced sulfur levels starting in 2004 for gasoline and 2006 for diesel fuel. We achieved compliance with these regulations and began production of ultra-low sulfur diesel fuel for on-road use prior to the June 1, 2006 deadline. The cost of achieving compliance with these regulations was approximately $850 million. Marathon will also be spending approximately $250 million from 2006 through 2010 to produce ultra-low sulfur diesel fuel for off-road use. Further, Marathon estimates that it will spend approximately $400 million over a four-year period beginning in 2008 to comply with Mobile Source Air Toxics II regulations relating to benzene. This is a preliminary estimate as the Mobile Source Air Toxics II regulations should be finalized in the first half of 2007.

The EPA has finalized new and revised National Ambient Air Quality Standards ("NAAQS") for fine particulate emissions and ozone. In connection with these new 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, in January 2004, the EPA proposed a rule called the Interstate Air Quality Rule ("IAQR") that would require significant reductions of SO2 and NOx emissions in numerous states. The final rule was promulgated on May 12, 2005, and the rule 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 ("EGUs"), 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 states may choose to propose more stringent fuels requirements to meet the CAIR requirements; however we cannot reasonably estimate the final financial impact of the state actions to implement the CAIR until the states have taken further action.

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.

Solid Waste

We continue to seek methods to minimize the generation of hazardous wastes in our operations. 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 are not expected to be material.

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.

Employees

We had 28,195 active employees as of December 31, 2006. Of that number, 19,132 were employees of SSA, most of whom 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.

Available Information

General information about Marathon, including the Corporate Governance Principles and Charters for the Audit Committee, Compensation Committee, Corporate Governance and Nominating Committee and Committee on Financial Policy, can be found at www.marathon.com. In addition, our Code of Business Conduct and Code of Ethics for Senior Financial Officers are available on the website at www.marathon.com/Our Values/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.

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 oil or natural gas prices, as well as refined product 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 oil and natural gas and refined product gross margins fluctuate widely. Our revenues, operating results and future rate of growth are highly dependent on the prices we receive for our oil, natural gas and refined products. Historically, the markets for oil, natural gas and refined products have been volatile and may continue to be volatile in the future. Many of the factors influencing prices of oil, natural gas and refined products are beyond our control. These factors include:

- worldwide and domestic supplies of and demand for oil, natural gas and refined products;
- the cost of exploring for, developing and producing oil, natural gas and 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-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 oil and natural gas, as well as on refined product gross margins, are uncertain.

Lower oil and natural gas prices, as well as lower refined product 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 oil and natural gas prices or refined product gross margins could require us to reduce our capital expenditures and impair the carrying value of our assets.

Estimates of oil and natural gas 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 oil and natural gas reserves.

The proved oil and natural gas reserves information related to Marathon 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 oil and natural gas prices in effect as of December 31, 2006, as well as other conditions in existence as of that date. Any significant future price changes will have a material effect on the quantity and present value of our proved reserves. Future reserve revisions could also result from changes in, among other things, governmental regulation and severance and other production taxes.

Reserve estimation is a subjective process that involves estimating volumes to be recovered from underground accumulations of oil and natural gas that cannot be directly measured. Estimates of economically recoverable oil 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;
- assumptions concerning future oil and natural gas prices; 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 reserves and future net cash flows based on the same available data. Because of the subjective nature of oil 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 oil 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 reserves reflected in this report should not be considered as the market value of the reserves attributable to our properties. As required by SEC Rule 4-10 of Regulation S-X, the estimated discounted future net revenues from our proved 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.

If we are unsuccessful in acquiring or finding additional reserves, our future oil 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 oil and natural gas properties generally declines as reserves are depleted. Except to the extent we acquire interests in additional properties containing proved reserves, conduct successful exploration and development activities or, through engineering studies, optimize production performance, identify additional reservoirs not currently producing or secondary recovery reserves, our proved reserves will decline materially as oil and natural gas is produced. Accordingly, to the extent we are not successful in replacing the oil 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 oil 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 regulations may reduce our refined product 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. Refined product 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, environmental regulations, particularly the 1990 amendments to the Clean Air Act, 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 refined product gross margins.

If we do not compete successfully with our competitors, our future operating performance and profitability could materially decline.

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. In addition, in implementing our integrated gas strategy, we compete with major integrated energy companies in bidding for and developing liquefied natural gas projects, which are very capital intensive. Many of our competitors have financial and other resources greater than those available to us. As a consequence, we may be at a competitive disadvantage in acquiring additional properties and bidding for and developing additional projects, such as LNG production facilities. Many of our larger competitors in the LNG market can complete more projects than we have the capacity to complete, which could lead those competitors to realize economies of scale that we are unable to realize. In addition, many of our larger competitors may be better able to respond to factors that affect the demand for oil and natural gas, such as changes in worldwide prices and levels of production, the cost and availability of alternative fuels and the application of government regulations.

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.

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 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. Approximately 56 percent of our oil and natural gas production in 2006 was derived from production outside the United States and approximately 72 percent of our proved reserves as of December 31, 2006, were located outside the United States.

There are many risks associated with operations in international markets, including changes in foreign governmental policies relating to crude oil, natural gas 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 crude oil, 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 the U.S. government 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

24

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. 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 exploration, drilling and production and could materially 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.

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:

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 $564 million as of December 31, 2006, including accrued interest of $11 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.

Under applicable law and regulations, we also may be liable for any defaults by United States Steel in the performance of its obligations to fund its ERISA pension plans and pay other obligations related to periods prior to the effective date of the separation.

United States Steel's senior unsecured debt is rated non-investment grade by two major credit rating agencies. 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.

If the transfer of ownership of various assets and operations by Marathon's former parent entity to Marathon was held to be a fraudulent conveyance or transfer, United States Steel's creditors may be able to obtain recovery from us or other relief detrimental to the holders of our common stock.

In July 2001, USX Corporation ("Old USX") effected a reorganization of the ownership of its businesses in which it created Marathon as its publicly owned parent holding company and transferred ownership of various assets and operations to Marathon, and it merged into a newly formed subsidiary which survived as United States Steel.

If a court in a bankruptcy case regarding United States Steel or a lawsuit brought by its creditors or their representative were to find that, under the applicable fraudulent conveyance or transfer law:

- the transfer by Old USX to Marathon or related transactions were undertaken by Old USX with the intent of hindering, delaying or defrauding its existing or future creditors; or

- Old USX received less than reasonably equivalent value or fair consideration, or no value or consideration, in connection with those transactions, and either it or United States Steel

  - was insolvent or rendered insolvent by reason of those transactions,

  - was engaged or about to engage in a business or transaction for which its assets constituted unreasonably small capital, or

  - intended to incur, or believed that it would incur, debts beyond its ability to pay as they mature,

then that court could determine those transactions entitled one or more classes of creditors of United States Steel to equitable relief from us. Such a determination could permit the unpaid creditors to obtain recovery from us or could result in other actions detrimental to the holders of our common stock. The measure of insolvency for purposes of these considerations would vary depending on the law of the jurisdiction being applied.

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 oil and gas properties, refineries, pipeline systems and other important physical properties of Marathon have been described previously. Except for oil and gas producing properties, which generally are leased, or as otherwise stated, such properties are held in fee. The plants and facilities have been constructed or acquired over a period of years and vary in age and operating efficiency. At the date of acquisition of important properties, titles were examined and opinions of counsel obtained, but no title examination has been made specifically for the purpose of this document. The properties classified as owned in fee generally have been held for many years without any material unfavorably adjudicated claim.

The basis for estimating oil and gas reserves is set forth in "Financial Statements and Supplementary Data Supplementary Information on Oil and Gas Producing Activities Estimated Quantities of Proved Oil and Gas Reserves" on pages F-46 through F-47.

Property, Plant and Equipment Additions

For property, plant and equipment additions, see "Management's Discussion and Analysis of Financial Condition, Cash Flows and Liquidity Capital Expenditures."

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. 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 specific allegation of underpayment for the month of May 2003 in the amount of $1,360, 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 May 2004, plaintiff environmental groups Environmental Defense et al filed suit against the U.S. BLM in Montana Federal District Court, alleging the agency did not adequately consider air quality impacts of coal bed methane and oil and gas operations in the Powder River Basin in Montana and Wyoming when preparing its environmental impact statements. Plaintiffs request that the BLM be ordered to cease issuing leases and permits for energy development, until additional analysis of predicted air impacts is conducted. Marathon and its subsidiary Pennaco Energy, Inc. intervened in this litigation.

MTBE Litigation

Marathon is a defendant along with many other refining companies in over 40 cases in 11 states alleging methyl tertiary-butyl ether ("MTBE") contamination in groundwater. All of these cases have been consolidated in a multi-district litigation in the Southern District of New York for preliminary proceedings. The judge in this multi-district litigation ruled on April 20, 2005 that some form of market share liability would apply. Market share liability enables a plaintiff to sue manufacturers who represent a substantial share of a market for a particular product and shift the burden of identification of who actually made the product to the defendants, effectively forcing a defendant to show that it did not produce the MTBE which allegedly caused the damage. The judge further allowed cases to go forward in New York and 11 other states, based upon varying theories of collective liability, and predicted that a new theory of market share liability would be recognized in Connecticut, Indiana and Kansas. The plaintiffs generally are water providers or governmental authorities and they allege that refiners, manufacturers and sellers of gasoline containing MTBE are liable for manufacturing a defective product and that the owners and operators of retail gasoline sites have allowed MTBE to be discharged into the groundwater. Several of these lawsuits allege contamination that is outside of Marathon's marketing area. A few of the cases seek approval as class actions. Many of the cases seek punitive damages or treble damages under a variety of statutes and theories. Marathon stopped producing MTBE at its refineries in October 2002. The potential impact of these recent cases and future potential similar cases is uncertain. The Company will defend these cases vigorously.

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 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. Plaintiffs seek class action status. In 2002, MPC conducted extensive cleaning operations at affected facilities and denies that any permanent damages resulted from the incident. MPC 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 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.

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 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, and another filed in April 2006, until August 2007 while the U.S. EPA mediates the matter between Montana, Wyoming and the Northern Cheyenne tribe.

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, 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.

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 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. 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 for new discharges it would adopt.

Other Proceedings

The following is a summary of proceedings involving Marathon that were pending or contemplated as of December 31, 2006 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 "Item 3. Legal Proceedings" above takes such matters into account.

Claims under CERCLA and related state acts have been raised with respect to the cleanup of various waste disposal and other sites. CERCLA is intended to facilitate the cleanup 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 cleanup 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 or timing of completion of environmental projects may differ materially from those stated in the forward-looking statements.

As of December 31, 2006, Marathon had been identified as a PRP at a total of nine CERCLA waste sites. Based on currently available information, which is in many cases preliminary and incomplete, Marathon believes that its liability for cleanup and remediation costs in connection with six of these sites will be under $1 million per site (with three of these six sites being under $100,000 each). As to the remaining three sites of the nine, Marathon believes that its liability for cleanup and remediation costs in connection with two of these sites will be under $4 million per site with the last site having costs that cannot be estimated at this time.

In addition, there are three 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.

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 cleanup and remediation costs in connection with 27 of these sites will be under $100,000 per site, that 45 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. Eleven sites have incurred remediation costs of more than $5 million per site and there are 17 sites with insufficient information to estimate future remediation costs.

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 30 years, Marathon anticipates spending approximately $7 million at this site. In 2007, interim remediation measures will 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 in 2006 and 2005 were $488,000 and $540,000, with expenditures in 2007 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.

In 2005, MPC received a Notice of Violation from the U.S. EPA alleging 33 violations of Clean Air Act fuels requirements. The alleged violations largely resulted from MPC's attest engagements submitted to the Agency under the Reformulated Gasoline and Anti Dumping programs. In 2006, MPC reached an administrative settlement with the U.S. EPA where MPC paid a civil penalty of $139,000 and resolved this Notice of Violation.

MPC received an enforcement action from the Minnesota Pollution Control Agency ("MPCA") in the fourth quarter of 2006 where the MPCA seeks a civil penalty of $121,800 for a release of catalyst from the fluid catalytic cracking unit at the St. Paul Park refinery in 2004 and other alleged violations. Discussions will be held with the MPCA in 2007 and the Company expects to resolve the matter within the year.

SEC Investigation Relating to Equatorial Guinea

By letter dated July 15, 2004, the United States Securities and Exchange Commission ("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 United States Senate Permanent Subcommittee on Investigations, which reviewed the transactions of various foreign governments, including that of Equatorial Guinea, with Riggs Bank. The investigation and hearing also reviewed the operations of U.S. oil 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.

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

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity and Related Stockholder Matters and Issuer Purchase 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 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 "Selected Quarterly Financial Data (Unaudited)" on page F-42.

As of January 31, 2007, there were 64,646 registered holders of Marathon common stock.

The 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.

The following table provides information about purchases by Marathon and its affiliated purchaser during the quarter ended December 31, 2006 of equity securities that are registered by Marathon pursuant to Section 12 of the Exchange Act:

ISSUER PURCHASES OF EQUITY SECURITIES

		(a)	(b)	(c)	(d)
Period		**Total Number of Shares Purchased[(a)(b)]**	**Average Price Paid per Share**	**Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[(d)]**	**Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs[(d)]**
10/01/06	10/31/06	2,317,869	$79.90	2,302,642	$664,177,964
11/01/06	11/30/06	2,214,981	$89.01	2,212,358	$467,266,675
12/01/06	12/31/06	1,859,740[(c)]	$94.13	1,815,000	$296,427,158
Total		6,392,590	$87.19	6,330,000	

(a) 46,872 shares of restricted stock were delivered by employees to Marathon, upon vesting, to satisfy tax withholding requirements.

(b) Under the terms of the Acquisition, Marathon paid Ashland shareholders cash in lieu of issuing fractional shares of Marathon's common stock to which such holder would otherwise be entitled. Marathon acquired 7 shares due to Acquisition exchanges and Ashland share transfers pending at the time of closing of the Acquisition.

(c) 15,711 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 "Plan") by the administrator of the Plan. Stock needed to meet the requirements of the Plan are either purchased in the open market or issued directly by Marathon.

(d) In January 2006, we announced a $2 billion share repurchase program. In January 2007, our Board of Directors authorized the extension of this program by an additional $500 million. As of February 21, 2007, the Company had repurchased 24.2 million common shares at a cost of $2 billion.

Item 6. Selected Financial Data

(In millions, except per share data)

	2006[(a)]	**2005[(a)]**	**2004**	**2003**	**2002**
Statement of Income Data:					
Revenues[(b)]	**$ 64,896**	$ 62,986	$ 49,465	$ 40,907	$ 31,295
Income from continuing operations	**4,957**	3,006	1,294	1,010	507
Net income	**5,234**	3,032	1,261	1,321	516
Basic per share data:					
Income from continuing operations	**$ 13.85**	$ 8.44	$ 3.85	$ 3.26	$ 1.63
Net income	**$ 14.62**	$ 8.52	$ 3.75	$ 4.26	$ 1.66
Diluted per share data:					
Income from continuing operations	**$ 13.73**	$ 8.37	$ 3.83	$ 3.25	$ 1.63
Net income	**$ 14.50**	$ 8.44	$ 3.73	$ 4.26	$ 1.66
Statement of Cash Flows Data:					
Capital expenditures from continuing operations	**$ 3,433**	$ 2,796	$ 2,141	$ 1,873	$ 1,520
Dividends paid	**547**	436	348	298	285
Dividends paid per share	**$ 1.53**	$ 1.22	$ 1.03	$ 0.96	$ 0.92

(In millions, except per share data)

	2006[a]	2005[a]	2004	2003	2002
Balance Sheet Data as of December 31:					
Total assets	**$ 30,831**	$ 28,498	$ 23,423	$ 19,482	$ 17,812
Total long-term debt, including capitalized leases	**3,061**	3,698	4,057	4,085	4,410

(a) 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.

(b) 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.

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

Marathon is engaged in worldwide exploration, production and marketing of crude oil and natural gas; domestic refining, marketing and transportation of crude oil and petroleum products, primarily in the Midwest, the upper Great Plains and southeastern 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 Item 1. Business, Item 1A. Risk Factors, Item 6. Selected Financial Data and Item 8. 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 accordance with "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, which could cause future outcomes to differ materially from those set forth in the forward-looking statements.

Unless specifically noted, amounts for the refining, marketing and transportation segment include the 38 percent interest in MPC held by Ashland prior to the Acquisition on June 30, 2005, and amounts for the integrated gas segment include the 25 percent interest held by SONAGAS (previously held by GEPetrol) in all periods and the 8.5 percent interest held by Mitsui and the 6.5 percent interest held by Marubeni since July 25, 2005.

Effective January 1, 2006, we revised our measure of segment income to include the effects of minority interests and income taxes related to the segments. In addition, the results of activities primarily associated with the marketing of our equity natural gas production, which had been presented as part of the Integrated Gas segment prior to 2006, are now included in the Exploration and Production segment. Segment results for all periods presented reflect these changes.

Overview

Exploration and Production

Exploration and production segment revenues correlate closely with prevailing prices for the various qualities of crude oil and natural gas we produce. The increase in our E&P segment revenues in 2006 is primarily related to increased production, particularly from Libya where the first liquid hydrocarbon sales occurred in the first quarter of 2006; however, our 2006 revenues also tracked the changes in market prices for commodities. Higher prices for crude oil early in 2006 reflected concerns about international supply due to unrest in oil-producing countries and the potential for hurricane damage in the U.S. Gulf of Mexico. As hurricane season came to an end without a major storm in the Gulf of Mexico and in the absence of significant international supply shortfalls or disruptions, crude oil prices declined. The average spot price during 2006 for West Texas Intermediate ("WTI"), a benchmark crude oil, was $66.25 per barrel, up from an average of $56.70 in 2005, and ended the year at $61.05. The average differential between WTI and Brent (an international benchmark crude oil) narrowed to $1.07 in 2006 from $2.18 in 2005. 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 benchmark.

Natural gas prices were lower in 2006 compared to 2005. A significant portion of our United States lower 48 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 $1.41 per mcf lower in 2006 than the 2005 average. Our natural gas prices in Alaska are largely contractual, while 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.

For information on commodity price risk management, see "Item 7A. Quantitative and Qualitative Disclosures about Market Risk."

E&P segment income during 2006 was up approximately 6 percent from 2005 levels, impacted by increased liquid hydrocarbon sales volumes, primarily due to the resumption of production in Libya, and the higher liquid hydrocarbon prices discussed above, partially offset by higher income taxes, primarily in Libya, operating costs and exploration expenses and decreases in natural gas sales volumes.

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. We purchase crude oil to satisfy our refineries' throughput requirements. 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 spot market gasoline and distillate prices and spot market 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 product and our level of manufacturing costs. We process significant amounts of sour crude oil which enhances our competitive position in the industry as sour crude oil typically can be purchased at a discount to sweet crude oil. Over the last three years, approximately 60 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 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 regulatory climate, logistical capabilities and expectations regarding the adequacy of refined product, ethanol and raw material supplies.

Together with our June 30, 2005 acquisition of the 38 percent minority interest in MPC, our improved refining and wholesale marketing gross margin in 2006 was the key driver of the 72 percent increase in RM&T segment income over 2005. The average refining and wholesale marketing gross margin increased to 22.88 cents per gallon in 2006 from 15.82 cents per gallon in 2005.

For information on commodity price risk management, see "Item 7A. Quantitative and Qualitative Disclosures about Market Risk."

Our seven refineries have an aggregate refining capacity of 974 mbpd of crude oil. During 2006, our refineries processed 980 mbpd of crude oil and 234 mbpd of other charge and blend stocks for a crude oil capacity utilization rate of 101 percent.

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 situations that impact driving conditions. Gross margins on merchandise sold at retail outlets tend to be less volatile than the gross margins 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 long-term 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. LNG, particularly in regard to our operations in Equatorial Guinea, is a key component of this integrated gas 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. Also included in the financial results of the IG segment are the costs associated with ongoing development of certain integrated gas projects. Methanol spot pricing is volatile largely because global methanol demand is 35 million tons and any major unplanned shutdown of or addition to production capacity can have a significant impact on the supply-demand balance.

2006 Operating Highlights

- We announced seven discoveries in Angola and Norway and continued our major development projects, enhancing our E&P operations by:
  - Resuming operations and achieving first crude oil liftings in Libya;
  - Acquiring leasehold positions in the Bakken Shale in North Dakota and eastern Montana and the Piceance Basin of Colorado and adding acreage in the Barnett Shale in north central Texas;
  - Progressing the Alvheim/Vilje development offshore Norway and receiving Norwegian Government approval of the Volund field plan for development and operation that includes its tie-back to Alvheim;
  - Progressing the Neptune deepwater Gulf of Mexico development;
  - Signing a production sharing contract for the 1.2 million acre Pasangkayu exploration block in Indonesia; and
  - Completing the sale of our Russian oil exploration and production businesses at a gain.
- We added net proved oil and natural gas reserves of 146 million boe, excluding 45 million boe of dispositions, while producing 134 million boe during 2006. Over the past three years, we have added net proved reserves of 648 million boe, excluding dispositions of approximately 46 million boe, while producing approximately 380 million boe.
- We achieved record refinery crude oil and total throughput and strengthened our RM&T business by:
  - Authorizing the projected $3.2 billion expansion of our Garyville refinery;
  - Completing the Tier II ultra-low sulfur diesel fuel projects on time and under budget;

Forming an ethanol joint venture and beginning construction of the venture's first ethanol plant in Greenville, Ohio;

Awarding a FEED contract at the Detroit refinery and launching a feasibility study at the Catlettsburg refinery for potential heavy oil upgrading projects; and

Acquiring strategic marine and terminal assets.

We increased Marathon Brand gasoline and diesel sales volumes 6 percent in 2006.

We increased Speedway SuperAmerica's (SSA) same store gasoline and diesel sales volume 2 percent and merchandise sales 8 percent over 2005.

We advanced our integrated gas strategy by:

Progressing our Equatorial Guinea LNG production facility to near completion, with commissioning begun in late 2006; and

Awarding a FEED contract to evaluate a possible second LNG production facility in Equatorial Guinea.

We issued a request for proposals for a potential Canadian oil sands venture.

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 Quantities of Oil and Natural Gas

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 oil 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 oil and natural gas.

Proved reserves are the estimated quantities of oil 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 2006, net revisions of previous estimates increased total proved reserves by 83 million boe (6 percent of the beginning-of-the-year reserves estimate). Positive revisions of 98 million boe were partially offset by 15 million boe in negative revisions.

Our estimation of net recoverable quantities of oil 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 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)," 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)." All 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 make up 80 percent of our reserves over a rolling four-year period. At December 31, 2006 we had met this goal. For 2006, Marathon 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 Marathon's 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 2006, 2005 or 2004.

The reserves of the Alba field in Equatorial Guinea comprise approximately 40 percent of our total proved oil and natural gas reserves as of December 31, 2006. The next five largest oil and gas producing asset groups the Waha concessions in Libya, the Alvheim development offshore Norway, the Brae area complex offshore the United Kingdom, the Kenai field in Alaska and the Oregon Basin field in the Rocky Mountain area of the United States comprise a total of approximately 30 percent of our total proved oil and natural gas reserves.

Depreciation and depletion of producing oil 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. A five percent increase in the amount of oil and natural gas reserves would change the depreciation and depletion rate from $6.92 per barrel to $6.59 per barrel, which would increase pretax income by approximately $45 million annually, based on 2006 production. A five percent decrease in the amount of oil and natural gas reserves would change the depreciation and depletion rate from $6.92 per barrel to $7.28 per barrel and would result in a decrease in pretax income of approximately $50 million annually, based on 2006 production.

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 which require fair value estimates include asset retirement obligations, guarantee obligations and stock-based compensation.

Under the purchase method of accounting, 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 2005, we made two significant acquisitions with an aggregate purchase price of $3.156 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 these acquisitions. We did not make any significant acquisitions in 2006. As of December 31, 2006, our recorded goodwill was $1.398 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, 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 requires assumptions about matters such as future oil and natural gas prices, estimated recoverable quantities of oil and natural gas, expected field performance and the political environment in the host country. An impairment of any of our large oil and gas producing properties 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 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.

During 2006, we recorded impairments of $25 million, including $20 million related to the Camden Hills field in the Gulf of Mexico and the associated Canyon Express pipeline. Natural gas production from the Camden Hills field ended during 2006 as a result of increased water production from the well. We did not have significant impairment charges during 2005. During 2004, we recorded an impairment of $32 million related to unproved properties and $12 million related to producing properties primarily as a result of unsuccessful developmental drilling activity in Russia.

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. Contract prices are linked to a basket of energy and other indices. The contract price is reset annually in October based on the previous twelve-month changes in the basket of indices. 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. 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 2006, the non-cash gains related to changes in fair value recognized in income from operations were $454 million. Non-cash losses of $386 million and $99 million were recognized in 2005 and 2004. These effects are primarily due to the U.K. 18-month forward natural gas price curve weakening 44 percent in 2006, while it strengthened 90 percent and 36 percent during 2005 and 2004.

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, 2006, we reported net deferred tax assets of $1.865 billion, which represented gross assets of $2.554 billion net of valuation allowances of $689 million.

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.

Pensions 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 plans due to the different projected liability durations of 9 years and 13 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 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 2006, 2005 and 2004, as well as the obligations and accumulated other comprehensive income reported on the balance sheets as of December 31, 2006 and 2005.

Of the assumptions used to measure the December 31, 2006 obligations and estimated 2007 net periodic benefit cost, the discount rate has the most significant effect on the periodic benefit cost reported for the plans. A 0.25 percent decrease in the discount rates of 5.80 percent for our U.S. pension plans and 5.90 percent for our other U.S. postretirement benefit plans would increase pension obligations and other postretirement benefit plan obligations by $93 million and $28 million and would increase defined benefit pension expense and other postretirement plan expense by $13 million and $2 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.

Contingent Liabilities

We accrue contingent liabilities for income and other tax deficiencies, environmental remediation, product liability claims and litigation claims when such contingencies are probable and estimable. Actual costs can differ from estimates for many reasons. For instance, the costs from settlement of 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 because of changes in laws, regulations and their interpretation; the determination of 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.

A liability is recorded for these types of contingencies if we determine the loss to be both probable and estimable. We generally record these losses as cost of revenues or selling, general and administrative expenses in the consolidated statements of income, except for tax contingencies, which are recorded as other taxes or provision for income 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.

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.

Each purchase and sale transaction has the characteristics of a separate legal transaction, including separate invoicing and cash settlement. Accordingly, we believed that we were required to account for these transactions separately. An accounting interpretation clarified the circumstances under which a matching buy/sell transaction should be viewed as a single transaction involving the exchange of inventory. For a further description of the accounting requirements and how they apply to matching buy/sell transactions, see Note 2 to the consolidated financial statements.

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.

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. The effect of this change on the refining and wholesale marketing gross margin per gallon for 2006 was not significant.

Consolidated Results of Operations

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

(In millions)

	2006	**2005**	**2004**
E&P	**$ 9,010**	$ 8,009	$ 6,412
RM&T	**55,941**	56,003	43,630
IG	**179**	236	190
Segment revenues	**65,130**	64,248	50,232
Elimination of intersegment revenues	**(688)**	(876)	(668)
Gain (loss) on long-term U.K. gas contracts	**454**	(386)	(99)
Total revenues	**$ 64,896**	$ 62,986	$ 49,465
Items included in both revenues and costs and expenses:			
Consumer excise taxes on petroleum products and merchandise	**$ 4,979**	$ 4,715	$ 4,463
Matching crude oil and refined product buy/sell transactions settled in cash:			
E&P	**$ 16**	$ 123	$ 167
RM&T	**5,441**	12,513	9,075
Total buy/sell transactions included in revenues	**$ 5,457**	$ 12,636	$ 9,242

E&P segment revenues increased $1.001 billion in 2006 from 2005 and $1.597 billion in 2005 from 2004. 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, almost completely offset the benefit of higher liquid hydrocarbon prices in 2006.

The 2005 increase in E&P segment revenues over 2004 was primarily the result of higher worldwide liquid hydrocarbon and natural gas prices and international liquid hydrocarbon sales volumes partially offset by lower domestic natural gas and liquid hydrocarbon sales volumes as illustrated in the table below. The decline in domestic volumes in 2005 resulted primarily from weather-related downtime in the Gulf of Mexico and natural declines in field production rates.

	2006	2005	2004
E&P OPERATING STATISTICS			
Net Liquid Hydrocarbon Sales (mbpd)[(a)]			
United States	**76**	76	81
Europe	**35**	36	40
Africa	**112**	52	32
Total International[(b)]	**147**	88	72
Worldwide Continuing Operations	**223**	164	153
Discontinued Operations[(c)]	**12**	27	17
Worldwide	**235**	191	170
Net Natural Gas Sales (mmcfd)[(d)(e)]			
United States	**532**	578	631
Europe	**243**	262	292
Africa	**72**	92	76
Total International	**315**	354	368
Worldwide	**847**	932	999
Total Worldwide Sales (mboepd)			
Continuing operations	**365**	319	320
Discontinued operations	**12**	27	17
Worldwide	**377**	346	337
Average Realizations[(f)]			
Liquid Hydrocarbons ($per bbl)			
United States	**$ 54.41**	$ 45.41	$ 32.76
Europe	**64.02**	52.99	37.16
Africa	**59.83**	46.27	35.11
Total International	**60.81**	49.04	36.24
Worldwide Continuing Operations	**58.63**	47.35	34.40
Discontinued Operations	**38.38**	33.47	22.65
Worldwide	**$ 57.58**	$ 45.42	$ 33.31
Natural Gas ($per mcf)			
United States	**$ 5.76**	$ 6.42	$ 4.89
Europe	**6.74**	5.70	4.13
Africa	**0.27**	0.25	0.25
Total International	**5.27**	4.28	3.33
Worldwide	**$ 5.58**	$ 5.61	$ 4.31

(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 46, 38, and 19 mmcfd in 2006, 2005 and 2004, respectively. Effective July 1, 2005, the methodology for allocating sales volumes between natural gas produced from the Brae complex and third-party natural gas production was modified, resulting in an increase in volumes representing natural gas acquired for injection and subsequent resale.

(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 gains of $25 million and $7 million in 2006 and 2005, and derivative losses of $152 million in 2004. Excluded from E&P segment revenues were gains of $454 million in 2006 and losses of $386 million and $99 million in 2005 and 2004 related to long-term natural gas sales contracts in the United Kingdom that are accounted for as derivative instruments. See "Item 7A. Quantitative and Qualitative Disclosures about Market Risk" on page 56.

RM&T segment revenues decreased by $62 million in 2006 from 2005 and increased by $12.373 billion in 2005 from 2004. The portion of RM&T revenues reported for matching buy/sell transactions decreased $7.072 billion and increased $3.438 billion in the same periods. The decrease in revenues from matching buy/sell transactions in 2006 was a result of the change in accounting for these transactions effective April 1, 2006, discussed above. Excluding matching buy/sell transactions, 2006 revenues increased primarily as a result of higher refined product prices and sales volumes. The 2005 increase primarily reflected higher refined product and crude oil prices and increased refined product sales volumes, partially offset by decreased crude oil sales volumes.

For additional information on segment results see page 43.

Income from equity method investments increased by $126 million in 2006 from 2005 and increased by $98 million in 2005 from 2004. Income from our LPG operations in Equatorial Guinea increased in both periods due to higher sales volumes as a result of the plant expansions completed in 2005. The increase in 2005 also included higher PTC income as a result of higher distillate gross margins.

Cost of revenues increased $4.609 billion in 2006 from 2005 and $7.106 billion in 2005 from 2004. 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 increase in both periods was also impacted by higher manufacturing expenses, primarily the result of higher contract services and labor costs in 2006 and higher purchased energy costs in 2005.

Purchases related to matching buy/sell transactions decreased $6.968 billion in 2006 from 2005 and increased $3.314 billion in 2005 from 2004, mostly in the RM&T segment. The decrease in 2006 was primarily related to the change in accounting for matching buy/sell transactions discussed above. The increase in 2005 was primarily due to increased crude oil prices.

Depreciation, depletion and amortization increased $215 million in 2006 from 2005 and $125 million in 2005 from 2004. RM&T segment depreciation expense increased in both years as a result of the increase in asset value recorded for our acquisition of the 38 percent interest in MPC on June 30, 2005. In addition, the Detroit refinery expansion completed in the fourth quarter of 2005 contributed to the RM&T depreciation expense increase in 2006. E&P segment depreciation expense for 2006 included a $20 million impairment of capitalized costs related to the Camden Hills field in the Gulf of Mexico and the associated Canyon Express pipeline. Natural gas production from the Camden Hills field ended in 2006 as a result of increased water production from the well.

Selling, general and administrative expenses increased $73 million in 2006 from 2005 and $134 million in 2005 from 2004. The 2006 increase was primarily because personnel and staffing costs increased throughout the year primarily as a result of variable compensation arrangements and increased business activity. Partially offsetting these increases were reductions in stock-based compensation expense. The increase in 2005 was primarily a result of increased stock-based compensation expense, due to the increase in our stock price during that year as well as an increase in equity-based awards, which was partially offset by a decrease in expense as a result of severance and pension plan curtailment charges and start-up costs related to EGHoldings in 2004.

Exploration expenses increased $148 million in 2006 from 2005 and $59 million in 2005 from 2004. Exploration expense related to dry wells and other write-offs totaled $166 million, $111 million and $47 million in 2006, 2005 and 2004. Exploration expense in 2006 also included $47 million for exiting the Cortland and Empire leases in Nova Scotia.

Net interest and other financing costs (income) reflected a net $37 million of income for 2006, a favorable change of $183 million from the net $146 million expense in 2005. Net interest and other financing costs decreased $16 million in 2005 from 2004. 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. The decrease in expense for 2005 was primarily a result of increased interest income on higher average cash balances and greater capitalized interest, partially offset by increased interest on potential tax deficiencies and higher foreign exchange losses. Included in net interest and other financing costs (income) are foreign currency gains of $16 million, losses of $17 million and gains of $9 million for 2006, 2005 and 2004.

Minority interest in income of MPC decreased $148 million in 2005 from 2004 due to our acquisition of the 38 percent interest in MPC on June 30, 2005.

Provision for income taxes increased $2.308 billion in 2006 from 2005 and $979 million in 2005 from 2004, primarily due to the $4.259 billion and $2.691 billion increases in income from continuing operations before income taxes. The increase in our effective income tax rate in 2006 was primarily a result of the income taxes related to our Libyan 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 2006, 2005 and 2004. See Note 11 to the consolidated financial statements for further discussion.

	2006	**2005**	**2004**
Statutory U.S. income tax rate	**35.0%**	35.0%	35.0%

	2006	2005	2004
Effects of foreign operations, including foreign tax credits	**9.9**	(0.8)	0.5
State and local income taxes net of federal income tax effects	**1.9**	2.5	1.6
Other tax effects	**(2.0)**	(0.4)	(0.9)
Effective income tax rate for continuing operations	**44.8%**	36.3%	36.2%

Discontinued operations for all periods reflects the operations of our former Russian oil exploration and production businesses which were sold in June 2006. An after-tax gain on the disposal of $243 million is included in discontinued operations for 2006. See Note 7 to the consolidated financial statements for additional information. Also included in 2004 is a $4 million adjustment to the gain on the 2003 sale of our exploration and production operations in western Canada.

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

Effective January 1, 2006, we revised our measure of segment income to include the effects of minority interests and income taxes related to the segments. In addition, the results of activities primarily associated with the marketing of our equity natural gas production, which had been presented as part of the integrated gas segment prior to 2006, are now included in the exploration and production segment. Segment results for all periods presented reflect these changes.

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 for each of the last three years is summarized and reconciled to net income in the following table.

(In millions)

	2006	2005	2004
E&P			
Domestic	**$ 873**	$ 983	$ 674
International	**1,130**	904	416
E&P segment income	**2,003**	1,887	1,090
RM&T	**2,795**	1,628	568
IG	**16**	55	37
Segment income	**4,814**	3,570	1,695
Items not allocated to segments, net of income taxes:			
Corporate and other unallocated items	**(212)**	(377)	(327)
Gain (loss) on long-term U.K. natural gas contracts[a]	**232**	(223)	(57)
Discontinued operations	**277**	45	(33)
Gain on disposition of Syria interest	**31**		
Deferred income taxes tax legislation changes	**21**	15	
other adjustments[b]	**93**		
Loss on early extinguishment of debt	**(22)**		
Gain on sale of minority interests in EGHoldings		21	
Corporate insurance adjustment[c]			(17)
Cumulative effect of change in accounting principle		(19)	
Net income	**$ 5,234**	$ 3,032	$ 1,261

(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" on page 37 for further discussion.

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

(c) Insurance expense in 2004 related to estimated future obligations to make certain insurance premium payments related to past loss experience.

United States 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.

U.S. E&P income increased $309 million in 2005 from 2004. This was the result of a $917 million pretax income increase primarily due to higher revenues as discussed above. The effective income tax rate was 37 percent in both years. Our cost of storm-related repairs as a result of 2005 hurricane activity in the Gulf of Mexico was not significant and our Gulf of Mexico production quickly returned to pre-storm levels. In late September 2004, certain production platforms in the Gulf of Mexico were evacuated due to hurricane activity. All facilities were back on line by October 1, 2004 with the exception of the Petronius platform which came back on line in March 2005. As a result of the damage to the Petronius platform, we recorded expense of $11 million in 2004 representing repair costs incurred, partially offset by the net effects of the property damage insurance recoveries and the related retrospective insurance premiums. We recorded income of $53 million in 2005 and $34 million in 2004 for business interruption insurance recoveries.

International E&P income increased $226 million 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 sales volumes and prices 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 Libyan 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.

International E&P income increased $488 million in 2005 from 2004, reflecting an increase in pretax income of $740 million and an effective income tax rate of 37 percent in both years. The revenue increase discussed above had the most significant impact on pretax income. Increases in production costs and depletion, depreciation and amortization related primarily to increased production partially offset the benefit of higher revenue. Exploration expenses were also higher in 2005.

RM&T segment income increased $1.167 billion in 2006 from 2005 and $1.060 billion in 2005 from 2004. Segment income in 2006 and 2005 benefited from the 38 percent minority interest in MPC that we acquired on June 30, 2005. Pre-tax income increased by $1.802 billion in 2006 from 2005 and $1.766 billion in 2005 from 2004. The pretax earnings reduction related to the minority interest was $376 million in 2005 and $539 million in 2004. The key driver of the increase in RM&T pretax income in both years was our refining and wholesale marketing gross margin which averaged 22.88 cents per gallon in 2006 compared to 15.82 cents in 2005 and 8.77 cents in 2004. 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. In 2005, the margin improved initially due to wider sweet/sour crude oil differentials and later due to the temporary impact that Hurricanes Katrina and Rita had on refined product prices and concerns about the adequacy of distillate supplies heading into that winter.

Included in the refining and wholesale marketing gross margin were pretax gains of $400 million in 2006 and pretax losses of $238 million in 2005 and $272 million in 2004 related to derivatives utilized primarily to manage price risk. These derivative gains and losses are largely offset by gains and losses on the physical commodity transactions related to these derivative positions. The change from derivative losses to derivative gains reflects both improvements in the realized effects of our derivatives programs as well as unrealized effects as a result of marking open derivatives positions to market. See further discussion under "Item 7A. Quantitative and Qualitative Disclosures about Market Risk."

We averaged 980 mbpd of crude oil throughput in 2006, or 101 percent of system capacity. We averaged 973 mbpd of crude oil throughput in 2005 and 939 mbpd in 2004, representing 102 percent and 99 percent of system capacity for those years. Our capacity increased in 2005 as a result of the Detroit refinery expansion from 74 to 100 mbpd.

The following table includes certain key operating statistics for the RM&T segment for each of the last three years.

	2006	2005	2004
RM&T OPERATING STATISTICS			
Refining and wholesale marketing gross margin ($per gallon)[(a)]	**$ 0.2288**	$ 0.1582	$ 0.0877
Refined products sales volumes (mbpd)[(b)(c)]	**1,425**	1,455	1,400
Matching buy/sell volumes included in refined products sales volumes (mbpd)[(c)]	**24**	77	71

(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 (SSA) 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 the remainder of 2006 than would have been reported under the previous accounting practices. See Note 2 to the consolidated financial statements.

IG segment income decreased $39 million in 2006 from 2005 compared to an increase of $18 million in 2005 from 2004. 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 increased $1.642 billion in 2006 primarily as a result of the capital expenditures and the additional capitalized asset retirement costs discussed below. Net property, plant and equipment as of the end of the last two years is summarized in the following table.

(In millions)

	2006	2005
E&P		
Domestic	**$ 3,636**	$ 2,811
International	**4,879**	4,737
Total E&P	**8,515**	7,548
RM&T	**6,452**	6,113
IG	**1,378**	1,145
Corporate	**308**	205
Total	**$ 16,653**	$ 15,011

Asset retirement obligations increased $333 million in 2006 from 2005 primarily due to upward revisions of previous estimates related to increasing cost estimates, primarily in the United Kingdom, and to the accrual of obligations for new properties, primarily the Alvheim/Vilje development in Norway and the LNG production facility in Equatorial Guinea.

Cash Flows

Net cash provided from operating activities totaled $5.488 billion in 2006, compared with $4.738 billion in 2005 and $3.766 billion in 2004. The $750 million increase in 2006 primarily reflects the impact of higher net income, partially offset by contributions of $635 million to our funded defined benefit pension plans and working capital changes. The 2005 increase mainly resulted from higher net income, partially offset by the effects of receivables which were transferred to Ashland at the Acquisition date.

Net cash used in investing activities totaled $2.955 billion in 2006, compared with $3.127 billion in 2005 and $2.324 billion in 2004. 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)

	2006	2005	2004
E&P			
Domestic	**$ 1,302**	$ 638	$ 405
International	**867**	728	435
Total E&P	**2,169**	1,366	840
RM&T	**916**	841	794
IG	**307**	571	488
Corporate	**41**	18	19
Total	**$ 3,433**	$ 2,796	$ 2,141

(In millions)	2006	2005	2004

The $637 million increase in capital expenditures in 2006 over 2005 primarily resulted from increased spending in the E&P segment and primarily relates to significant acreage acquisitions in the Bakken Shale in North Dakota and eastern Montana and the Piceance Basin of Colorado, as well as to continued work on the Alvheim/Vilje development offshore Norway and the Neptune development in the Gulf of Mexico. The $264 million decrease in integrated gas spending reflects the fact that the LNG production facility in Equatorial Guinea is nearing completion. The $655 million increase in 2005 capital expenditures over 2004 mainly resulted from increased spending related to the Alvheim development and the Equatorial Guinea LNG production facility.

Acquisitions in 2006 primarily included cash payments of $718 million associated with our re-entry into Libya. Acquisitions in 2005 included cash payments of $506 million for the acquisition of Ashland's 38 percent ownership in MPC. For further discussion of acquisitions, see Note 6 to the consolidated financial statements.

Disposal of assets and of discontinued operations totaled $966 million in 2006, compared with $131 million in 2005 and $76 million in 2004. 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. In 2006, other disposals of assets included proceeds from the sale of 90 percent of our interest in Syrian natural gas fields, SSA stores and other domestic production and transportation assets. In 2005 and 2004, proceeds were primarily from the sale of various domestic producing properties and SSA stores.

Net cash used in financing activities totaled $2.581 billion in 2006, compared with $2.345 billion in 2005, and net cash provided of $527 million in 2004. Significant uses of cash in financing activities during 2006 included common stock repurchases under a previously announced plan, which is discussed under Liquidity and Capital Resources, dividend payments, the repayment of our 6.65% notes that matured during 2006 and 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 of MPC. In 2004, cash provided from financing activities was primarily related to the issuance of 34,500,000 shares of common stock on March 31, 2004, resulting in net proceeds of $1.004 billion. The change from 2004 to 2005 also included an increase in dividends paid and distributions to the minority shareholder of MPC prior to the Acquisition, net of an increase in contributions from the minority shareholders of EGHoldings.

Derivative Instruments

See "Quantitative and Qualitative Disclosures about Market Risk" on page 56, for a discussion of derivative instruments and associated market risk.

Dividends to Stockholders

Dividends of $1.53 per common share or $548 million were paid during 2006. On January 29, 2007, our Board of Directors declared a dividend of $0.40 cents per share on our common stock, payable March 12, 2007, to stockholders of record at the close of business on February 21, 2007.

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+. Because of the liquidity and capital resource alternatives available to us, including internally generated cash flow, 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 may ultimately be paid in connection with contingencies.

During 2006, we entered into an amendment to our $1.5 billion five-year revolving credit agreement, expanding the size of the facility to $2.0 billion and extending the termination date from May 2009 to May 2011. Concurrent with this amendment, the $500 million MPC revolving credit facility was terminated. At December 31, 2006, there were no borrowings against this facility. At December 31, 2006, we had no commercial paper outstanding under our U.S. commercial paper program that is backed by the five-year revolving credit facility.

During 2006 we entered into a loan agreement which allows borrowings of up to $525 million from the Norwegian export credit agency based upon the amount of qualifying purchases by Marathon of goods and services from Norwegian suppliers. The loan agreement provides for either a fixed or floating interest rate option at the time of the initial drawdown. Should we elect to borrow under the agreement, the initial drawdown can only occur in June 2007.

As a condition of the closing agreements for the Acquisition, we are required to maintain MPC on a stand-alone basis financially through June 30, 2007. During this period of time, capital contributions into MPC are prohibited and MPC is prohibited from incurring additional debt, except for borrowings under an existing intercompany loan facility to fund an expansion project at MPC's Detroit refinery and in the event of limited extraordinary circumstances. There are no restrictions against MPC making intercompany loans or declaring dividends to its parent. We believe that the

existing cash balances of MPC and cash provided from its operations will be adequate to meet its stand-alone liquidity requirements over the remainder of this two-year period.

As of December 31, 2006, there was $1.7 billion aggregate amount of common stock, preferred stock and other equity securities, debt securities, trust preferred securities or other securities, including securities convertible into or exchangeable for other equity or debt securities available to be issued under the $2.7 billion universal shelf registration statement filed with the Securities and Exchange Commission in 2002.

Our cash-adjusted debt-to-capital ratio (total-debt-minus-cash to total-debt-plus-equity-minus-cash) was six percent at December 31, 2006, compared to 11 percent at year-end 2005 as shown below. This includes $519 million of debt that is serviced by United States Steel.

(Dollars in millions) **December 31**	**2006**	2005
Long-term debt due within one year	**$ 471**	$ 315
Long-term debt	**3,061**	3,698
Total debt	**$ 3,532**	$ 4,013
Cash	**$ 2,585**	$ 2,617
Equity	**$ 14,607**	$ 11,705
Calculation:		
Total debt	**$ 3,532**	$ 4,013
Minus cash	**2,585**	2,617
Total debt minus cash	**947**	1,396
Total debt	**3,532**	4,013
Plus equity	**14,607**	11,705
Minus cash	**2,585**	2,617
Total debt plus equity minus cash	**$ 15,554**	$ 13,101
Cash-adjusted debt-to-capital ratio	**6%**	11%

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

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.

Stock Repurchase Program

In January 2006, we announced a $2 billion share repurchase program. In January 2007, our Board of Directors authorized the extension of this share repurchase program by an additional $500 million. As of February 21, 2007, we had repurchased 24.2 million common shares at a cost of $2 billion. We anticipate completing the additional $500 million in share repurchases during the first half of 2007. Purchases under the program may be in either open market transactions, including block purchases, or in privately negotiated transactions. We will use cash on hand, cash generated from operations or cash from available borrowings to acquire shares. This program may be changed based upon our financial condition or changes in market conditions and is subject to termination prior to completion.

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

Contractual Cash Obligations

The table below provides aggregated information on our obligations to make future payments under existing contracts as of December 31, 2006.

Summary of Contractual Cash Obligations

(In millions)	Total	2007	2008-2009	2010-2011	Later Years
Long-term debt (excludes interest)[(a)(b)]	$ 3,398	$ 450	$ 400	$ 143	$ 2,405
Sale-leaseback financing (includes imputed interest)[(a)]	75	20	22	22	11
Capital lease obligations[(a)]	141	16	33	33	59
Operating lease obligations[(a)]	851	154	286	158	253
Operating lease obligations under sublease[(a)]	32	5	11	11	5
Purchase obligations:					
Crude oil, refinery feedstock, refined product and ethanol contracts[(c)]	14,419	12,588	852	655	324
Transportation and related contracts	1,445	515	323	201	406
Contracts to acquire property, plant and equipment	1,703	935	719	37	12
LNG terminal operating costs[(d)]	178	13	24	25	116
Service and materials contracts[(e)]	602	210	231	81	80
Unconditional purchase obligations[(f)]	62	7	14	14	27
Commitments for oil and gas exploration (non-capital)[(g)]	100	57	31	2	10
Total purchase obligations	18,509	14,325	2,194	1,015	975
Other long-term liabilities reported in the consolidated balance sheet:					
Defined benefit postretirement plan obligations[(h)]	1,627	97	164	276	1,090
Total contractual cash obligations[(i)]	**$ 24,633**	**$ 15,067**	**$ 3,110**	**$ 1,658**	**$ 4,798**

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

(b) We anticipate cash payments for interest of $227 million for 2007, $364 million for 2008-2009, $357 million for 2010-2011 and $1.387 billion for the remaining years for a total of $2.335 billion.

(c) The majority of these contractual obligations as of December 31, 2006 relate to contracts to be satisfied within the first 180 days of 2007. 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. See Note 30 to the consolidated financial statements for a complete discussion of our 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) We have obligations consisting of pensions and other postretirement benefits including medical and life insurance. We have estimated projected funding requirements through 2016.

(i) Includes $581 million of contractual cash obligations that have been assumed by United States Steel. For additional information, 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" on page 49.

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 forms of guarantees to unconsolidated affiliates, United States Steel and others. These arrangements are described in Note 30 to the consolidated financial statements.

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 30 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 $340 million as of December 31, 2006. Of this amount, $217 million relates to PTC. If any of these investees default, we have no obligation to support the debt. Our partner in PTC has guaranteed $75 million of the total PTC debt.

Obligations Associated with the Separation of United States Steel

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, to holders of our USX U. S. Steel Group class of common stock in exchange for all outstanding shares of Steel Stock on a one-for-one basis.

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 Marathon 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 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 the assumed leases.

As of December 31, 2006, we have identified the following obligations totaling $564 million 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 $11 million at December 31, 2006.

- $60 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, 2006.

- $44 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, 2006.

- $34 million of operating lease obligations, $31 million of which was in turn 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. For further discussion of the Clairton 1314B guarantee, see Note 3 to the consolidated financial statements.

Of the total $564 million, obligations of $530 million and corresponding receivables from United States Steel were recorded on our consolidated balance sheet as of December 31, 2006 (current portion $32 million; long-term portion $498 million). The remaining $34 million was related to off-balance sheet arrangements and contingent liabilities of United States Steel.

The table below provides aggregated information on the portion of our obligations to make future payments under existing contracts that have been assumed by United States Steel as of December 31, 2006:

Summary of Contractual Cash Obligations Assumed by United States Steel

(In millions)	Total	2007	2008-2009	2010-2011	Later Years
Contractual obligations assumed by United States Steel					
Long-term debt[a]	$ 415	$	$	$	$ 415
Sale-leaseback financing (includes imputed interest)	75	20	22	22	11
Capital lease obligations	58	10	19	19	10
Operating lease obligations	3	3			
Operating lease obligations under sublease	30	5	10	10	5
Total contractual obligations assumed by United States Steel	**$ 581**	**$ 38**	**$ 51**	**$ 51**	**$ 441**

(a) We anticipate cash payments for interest of $23 million for 2007, $46 million for 2008-2009, $45 million for 2010-2011 and $239 million for the later years to be assumed by United States Steel.

Marathon and United States Steel have entered into a tax sharing agreement that allocates tax liabilities relating to taxable periods ended on or before December 31, 2001. In 2006 and 2005, in accordance with the terms of the tax sharing agreement, we 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 U.S. federal income tax returns under the tax sharing agreement was made in January 2007.

United States Steel reported in its Form 10-K for the year ended December 31, 2006, that it has significant restrictive covenants related to its indebtedness including cross-default and cross-acceleration clauses on selected debt that could have an adverse effect on its financial position and liquidity. However, United States Steel 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. We own a 52 percent interest in an onshore LPG processing plant in EG through an equity method investee, Alba Plant LLC. Additionally, we own a 45 percent interest in an onshore methanol production plant through AMPCO, an equity method investee. We sell our marketed natural gas from the Alba field to Alba Plant LLC and AMPCO. AMPCO uses the natural gas to manufacture methanol and sells the methanol through another equity method investee, AMPCO Marketing LLC.

Sales to our 50 percent equity method investee, PTC, which consists primarily of refined petroleum products, accounted for two percent or less of our total sales revenue for 2006, 2005 and 2004. PTC is the largest travel center network in the United States and operates 269 travel centers in the United States and Canada. Prior to the Acquisition on June 30, 2005, Ashland was a related party as a result of its 38 percent minority interest in MPC. 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 and 2004. We believe that these transactions were conducted under terms comparable to those with unrelated parties.

Marathon holds a 60 percent interest, SONAGAS holds a 25 percent interest, Mitsui holds an 8.5 percent interest and Marubeni holds a 6.5 percent interest in EGHoldings. As of December 31, 2006, total expenditures of $1.363 billion, including $1.300 billion of capital expenditures, related to the Equatorial Guinea LNG production facility have been incurred. Cash of $234 million held in escrow to fund future contributions from SONAGAS to EGHoldings is classified as restricted cash and is included in investments and long-term receivables as of December 31, 2006. Our current receivables from and payables to the interest holders in EGHoldings are $13 million and $232 million as of December 31, 2006, including a payable to SONAGAS of $229 million.

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)	2006	2005	2004
Capital	**$ 166**	$ 390	$ 433
Compliance			
Operating & maintenance	**319**	250	215
Remediation[(b)]	**20**	25	32
Total	**$ 505**	$ 665	$ 680

(a) Amounts are determined based on American Petroleum Institute survey guidelines.

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

Our environmental capital expenditures accounted for 5 percent of capital expenditures for continuing operations in 2006, 14 percent in 2005 and 20 percent in 2004.

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 $159 million or 8 percent of capital expenditures in 2007. Predictions beyond 2007 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 $277 million in 2008; however, actual expenditures may vary as the number and scope of environmental projects are revised as a result of improved technology or changes in regulatory requirements and could increase if additional projects are identified or additional requirements are imposed.

Of particular significance to our refining operations were U.S. EPA regulations that required reduced sulfur levels starting in 2004 for gasoline and 2006 for diesel fuel. We achieved compliance with these regulations and began production of ultra-low sulfur diesel fuel for on-road use prior to the June 1, 2006 deadline. The cost of achieving compliance with these regulations was approximately $850 million. We will also be spending approximately $250 million from 2006 through 2010 to produce ultra-low sulfur diesel fuel for off-road use. Further, we estimate that we will spend approximately $400 million over a four-year period beginning in 2008 to comply with Mobile Source Air Toxics II regulations relating to benzene. This is a preliminary estimate as the Mobile Source Air Toxics II regulations should be finalized in the first half of 2007.

During 2001, MPC 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 MPC to specific control technologies and implementation schedules for environmental expenditures and improvements to its refineries over approximately an eight-year period. In addition, MPC 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.

The oil industry across the U.K. continental shelf is making reductions in the amount of oil in its produced water discharges pursuant to the Department of Trade and Industry initiative under the Oil Pollution Prevention and Control Regulations ("OSPAR") of 2005. In compliance with these regulations, we have almost completed our OSPAR project for the Brae field to make the required reductions of oil in its produced water discharges. Our share of capital costs for the project is $7 million.

For information on legal proceedings related to environmental matters, see "Item 3. Legal Proceedings."

Outlook

Capital, Investment and Exploration Budget

We approved a capital, investment and exploration budget of $4.242 billion for 2007, which includes budgeted capital expenditures of $3.886 billion. This represents a 16 percent increase over 2006 actual spending. The primary focus of the 2007 budget is to find additional oil and natural gas reserves, develop existing fields, strengthen RM&T assets and continue implementation of the integrated gas strategy. The budget includes worldwide production spending of $1.429 billion primarily in the United States, Norway, Libya and Ireland. The worldwide exploration budget of $802 million includes plans to drill 14 to 17 significant exploration or appraisal wells. Other activities will focus primarily on areas within or adjacent to our onshore producing properties in the United States. The budget includes $1.464 billion for RM&T, primarily for refining projects including the 180 mbpd Garyville refinery expansion project and the FEED for a potential Detroit refinery heavy oil upgrading project which would allow us to process increased volumes of Canadian oil sands production. The RM&T budget also includes increased investments in transportation and logistics, a strategically important area of the business, including the expansion of our ethanol blending capabilities at terminals in the Midwest and Southeast. The integrated gas budget of $331 million is primarily for completion of the LNG processing facility in Equatorial Guinea, as well as FEED expenditures associated with a potential expansion of that facility. The remaining $216 million is designated for capitalized interest and corporate activities.

Exploration and Production

The seven announced discoveries in 2006 (six in deepwater Angola and one in Norway) resulted from our balanced exploration strategy which places an emphasis on near-term production opportunities, while retaining an appropriate exposure to longer-term options. Major exploration activities, which are currently underway or under evaluation, include those:

- offshore Angola, where we have participated in 13 discoveries on Block 31, in which we hold a 10 percent outside-operated interest. In 2006, we announced the Urano, Titania and Terra discoveries, as well as an unnamed discovery. Current plans call for a potential development area in the northeastern part of Block 31, which encompasses the Plutao, Saturno, Marte, Venus and Terra discoveries. The remaining discoveries are being evaluated for potential development. We have secured rig capacity for and plan to participate in exploration wells on Block 31 during 2007;

- offshore Angola on Block 32 in which we hold a 30 percent outside-operated interest and where we participated in five discoveries through 2006, Gindungo, Canela, Gengibre, Mostarda and Salsa, and announced two additional discoveries in 2007, Manjericao and Caril. These discoveries move Block 32 closer toward establishment of a commercial development. We have secured rig capacity for and plan to participate in exploration wells on Block 32 during 2007;

- 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 and the future LNG production facility on Bioko Island. We own a 63 percent interest in the Alba Block and serve as operator;

- in Norway, where we now own interests in 15 licenses in the Norwegian sector of the North Sea and plan to drill one or two exploration wells during 2007; and

- in the Gulf of Mexico, where we plan to participate in two to three exploration wells during 2007. We have secured rig capacity to drill two wells and our ability to drill the third well depends upon securing additional rig capacity.

During 2006, 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 Libya, where we re-entered the Waha concessions at the end of 2005 and achieved first production in January 2006. 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 Norway, where our Alvheim/Vilje development will consist of a floating production, storage and offloading vessel with subsea infrastructure for five drill centers and associated flow lines. Construction on the project is nearly complete and commissioning has commenced. First production is expected during the second quarter 2007, at which time four wells will be available, and drilling activities will continue into 2008. A peak net production rate of 75 mboepd is expected in early 2008. The Alvheim development includes the Kneler, Boa and Kameleon fields in which we own a 65 percent interest and serve as operator. We own a 47 percent outside-operated interest in the nearby Vilje discovery. Also, plans for development of the Volund discovery as a tie-back to the Alvheim development were approved by the Norwegian Government in early 2007. First production is expected from Volund in the second quarter of 2009. We own a 65 percent interest in Volund and serve as operator;

in the Gulf of Mexico, where the Neptune development is on target for first production by early 2008. We own a 30 percent outside-operated interest in Neptune;

in Ireland, where the Corrib natural gas development project has re-commenced and we expect first production in 2009. We own a 19 percent outside-operated interest in Corrib;

in the Piceance Basin where we plan to drill approximately 700 wells over the next ten years, with first production expected in late 2007; and

in the Bakken Shale where we plan to drill approximately 300 locations over the next five years.

We estimate that our 2007 production available for sale will average approximately 390 to 425 mboepd, excluding the impact of acquisitions and dispositions. With the developments we have under construction, we estimate our production available for sale will grow to 465 to 520 mboepd by 2010, excluding acquisitions and dispositions. Projected liquid hydrocarbon and natural gas production available for sale is 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, production decline rates of mature fields, 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.

In 2006, we issued a request for proposals to engage interested parties in a process that could lead to a Canadian oil sands venture. This process is intended to explore various commercial arrangements under which we would provide heavy Canadian oil sands crude oil processing capacity in exchange for an equity interest in a Canadian oil sands project through a joint venture, or other alternative business arrangements that potential partners may choose to propose.

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, the timing of production from the Neptune development, the Piceance Basin, the combined 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 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 in Blocks 31 and 32 could further be affected by presently known data concerning size and character of reservoirs, economic recoverability, future drilling success and production experience. The above discussion also contains forward-looking statements concerning a potential Canadian oil sands venture. Factors that could affect the formation of a Canadian oil sands venture include unforeseen difficulty in negotiation of definitive agreements, results of front-end engineering and design work, inability or delay in obtaining necessary government and third-party approvals, continued favorable investment climate, and other geological, operating and economic considerations. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Refining, Marketing and Transportation

Throughout 2006, 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 2006 average daily crude oil throughput exceeded the record throughput achieved in 2005.

In 2006, our Board of Directors approved a projected $3.2 billion expansion of our Garyville refinery by 180 mbpd to 425 mbpd, which will increase our total refining capacity to 1.154 mmbpd. We recently received air permit approval from the Louisiana Department of Environmental Quality for this project and construction is expected to begin in mid-2007, with startup planned for the fourth quarter of 2009. When completed, this expansion will enable the refinery to provide an additional 7.5 million gallons of clean transportation fuels to the market each day.

We have also commenced front-end engineering and design for a potential heavy oil upgrading project at our Detroit refinery which would allow us to process increased volumes of Canadian oil sand production and are undertaking a feasibility study for a similar upgrading project at our Catlettsburg refinery.

In 2006, we signed a definitive agreement forming a joint venture that will construct and operate one or more ethanol production plants. Our partner in the joint venture will provide the day-to-day management of the plants, as well as grain procurement, and distillers dried grain marketing and ethanol management services. This venture will enable us to maintain the reliability of a portion of our future ethanol supplies. Together with our partner, we selected the venture's initial plan site, Greenville, Ohio, and construction has commenced on a 110 million gallon per year ethanol facility. The facility is expected to be operational as soon as the first quarter of 2008.

The above discussion includes forward-looking statements concerning the planned expansion of the Garyville refinery, potential heavy oil refining upgrading projects and a joint venture that would construct and operate ethanol plants. Some factors that could affect the Garyville expansion project and the ethanol plant construction, management and development include necessary government and third party approvals, transportation logistics, availability of materials and labor, unforeseen hazards such as weather conditions and other risks customarily associated with construction projects. The Garyville project may be further affected by crude oil supply. These factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements. Factors that could affect the heavy oil refining upgrading projects include unforeseen difficulty in negotiation of definitive agreements, results of front-end engineering and design work, approval of our Board of Directors, inability or delay in obtaining necessary government and third-party approvals, continued favorable investment climate, and other geological, operating and economic considerations.

Integrated Gas

Construction of the LNG production facility in Equatorial Guinea continues ahead of its original schedule with the first shipments of LNG projected for the second quarter of 2007. Construction is nearly complete and commissioning has commenced. We own a 60 percent interest in Equatorial Guinea LNG Holdings Limited. We are currently seeking additional natural gas supplies to allow full utilization of this LNG facility, which is designed to have a higher capacity and a longer life than the current contract to supply 3.4 million metric tons per year for 17 years.

Once the Equatorial Guinea LNG production facility commences its principal operations and begins to generate revenue, we must assess whether or not EGHoldings continues to be a variable interest entity ("VIE"). We consolidate EGHoldings because it is a VIE and we are its primary beneficiary. Despite the fact that we hold majority ownership, we would not consolidate EGHoldings if it ceased to be a VIE because the minority shareholders have substantive participating rights. If EGHoldings ceased to be a VIE, we would account for our interest using the equity method of accounting.

In 2006, with our project partners, we awarded a FEED contract for initial work related to a potential second LNG production facility on Bioko Island, Equatorial Guinea. The FEED work is expected to be completed during 2007. The scope of the FEED work for the potential 4.4 million metric tones per annum LNG facility includes feed gas metering, liquefaction, refrigeration, ethylene storage, boil off gas compression, product transfer to storage and LNG product metering. A final investment decision is expected in early 2008.

Atlantic Methanol Production Company LLC underwent a scheduled maintenance shutdown in 2006, during which bottlenecks in several parts of the plant were also removed. Deliveries resumed in October 2006 and AMPCO expects to reach its full expansion capacity during 2007.

The above discussion contains forward looking statements with respect to the timing and levels of production associated with the LNG production facility and the possible expansion thereof. Factors that could affect the LNG production facility include unforeseen problems arising from commissioning of the facilities, unforeseen hazards such as weather conditions and other operating considerations such as shipping the LNG. In addition to these factors, other factors that could potentially affect the possible expansion of the current LNG production facility and the development of additional LNG capacity through additional projects include partner approvals, access to sufficient natural gas volumes through exploration or commercial negotiations with other resource owners and access to sufficient regasification capacity. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Accounting Standards Not Yet Adopted

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 will be effective January 1, 2008, and retrospective application is not permitted. Should we elect to apply the fair value option to any eligible items that exist at January 1, 2008, the effect of the first remeasurement to fair value would be reported as a cumulative effect adjustment to the opening balance of retained earnings. We are currently evaluating the provisions of this statement.

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. For us, SFAS No. 157 will be effective January 1, 2008, with early application permitted. We are currently evaluating the provisions of this statement.

In September 2006, the 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. We expense such costs in the same annual period as incurred; however, estimated annual major maintenance costs are recognized as expense throughout the year on a pro rata basis. As such, adoption of FSP No. AUG AIR-1 will have no impact on our annual consolidated financial statements. We are required to adopt the FSP effective January 1, 2007. We do not believe the provisions of FSP No. AUG AIR-1 will have a significant impact on our interim consolidated financial statements.

In July 2006, the FASB issued FASB Interpretation 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. For us, the provisions of FIN No. 48 are effective January 1, 2007. We do not believe adoption of this statement will have a significant effect on our consolidated results of operations, financial position or cash flows.

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. We are required to adopt SFAS No. 156 effective January 1, 2007. We do not expect adoption of this statement to have a significant effect on our consolidated results of operations, financial position or cash flows.

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 provides 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. For us, SFAS No. 155 is effective for all financial instruments acquired or issued on or after January 1, 2007. We do not expect adoption of this statement to have a significant effect on our consolidated results of operations, financial position or cash flows.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Management Opinion Concerning Derivative Instruments

Management has authorized the use of futures, forwards, swaps and combinations of options to manage exposure to market fluctuations in commodity prices, interest rates and foreign currency exchange rates.

We use commodity-based derivatives to manage price risk related to the purchase, production or sale of crude oil, natural gas and refined products. To a lesser extent, we are exposed to the risk of price fluctuations on natural gas liquids and petroleum feedstocks used as raw materials and on purchases of ethanol.

Our strategy generally has been 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 derivative instruments, including option combinations, as part of the overall risk management program to manage commodity price risk in our different businesses. As market conditions change, we evaluate our risk management program and could enter into strategies that assume greater market risk.

Our E&P segment primarily uses commodity derivative instruments selectively to protect against price decreases on portions of our future production when deemed advantageous to do so. We also use derivatives to protect the value of natural gas purchased and injected into storage in support of production operations. We use commodity derivative instruments to mitigate the price risk associated with the purchase and subsequent resale of natural gas on purchased volumes and anticipated sales volumes.

Our RM&T segment uses commodity derivative instruments:

- to mitigate the price risk:
  - between the time foreign and domestic crude oil and other feedstock purchases for refinery supply are priced and when they are actually refined into salable petroleum products,
  - on fixed price contracts for ethanol purchases,
  - associated with anticipated natural gas purchases for refinery use, and
  - associated with freight on crude oil, feedstocks and refined product deliveries;
- to protect the value of excess refined product, crude oil and liquefied petroleum gas inventories;
- to protect margins associated with future fixed price sales of refined products to non-retail customers;
- to protect against decreases in future crack spreads; and
- to take advantage of trading opportunities identified in the commodity markets.

We use financial derivative instruments to manage foreign currency exchange rate exposure on certain foreign currency denominated capital expenditures, operating expenses and tax payments.

We use financial derivative instruments to manage certain interest rate risk exposures. As we enter into these derivatives, assessments are made as to the qualification of each transaction for hedge accounting.

We believe that our use of derivative instruments along with risk assessment procedures and internal controls does not expose us to material risk. However, 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 consolidated financial position or liquidity.

Commodity Price Risk

Sensitivity analyses of the incremental effects on income from operations ("IFO") of hypothetical 10 percent and 25 percent changes in commodity prices for open derivative commodity instruments as of December 31, 2006 and December 31, 2005, are provided in the following table:

(In millions)

Commodity Derivative Instruments[b][c]:	**10%**	**25%**	**10%**	**25%**
Crude oil[d]	**$**	**$**	$ 11[e]	$ 25[e]
Natural gas[d]	**47[e]**	**119[e]**	78[e]	195[e]
Refined products[d]	**11[f]**	**28[f]**	6[e]	15[e]

(a) We remain at risk for possible changes in the market value of 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 analyses. Amounts reflect hypothetical 10 percent and 25 percent changes in closing commodity prices, excluding basis swaps, for each open contract position at December 31, 2006 and 2005. Included in the natural gas impacts shown above are effects related to the long-term U.K. natural gas contracts, which were $54 million in 2006 and $90 million in 2005, for hypothetical price changes of 10 percent and were $138 million in 2006 and $225 million in 2005 for hypothetical price changes of 25 percent. We evaluate our portfolio of derivative commodity 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, 2006, would cause future IFO effects to differ from those presented in this table.

(b) The number of net open contracts for the E&P segment varied throughout 2006, from a low of 316 contracts on June 27, 2006 to a high of 1,634 contracts on January 2, 2006, and averaged 1,054 for the year. The number of net open contracts for the RM&T segment varied throughout 2006, from a low of 166 contracts on December 7, 2006 to a high of 25,123 contracts on August 23, 2006, and averaged 13,154 for the year. The derivative commodity 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) The calculation of sensitivity amounts for basis swaps assumes that the physical and paper indices are perfectly correlated. Gains and losses on options are based on changes in intrinsic value only.

(d) 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.

(e) Price increase.

(f) Price decrease.

E&P Segment

Derivative gains of $25 million in 2006 and $7 million in 2005 and losses of $152 million in 2004 are included in E&P segment results. Additionally, losses from discontinued cash flow hedges of $3 million are included in 2004 segment results. The discontinued cash flow hedge amounts were reclassified from accumulated other comprehensive income as it was no longer probable that the original forecasted transactions would occur. The results of activities primarily associated with the marketing of our equity natural gas production, which had been presented as part of the Integrated Gas segment prior to 2006, are included in the E&P segment for all periods presented.

Excluded from E&P segment results were gains of $454 million in 2006 and losses of $386 million in 2005 and $99 million in 2004 related to long-term natural gas contracts in the United Kingdom that are accounted for as derivative instruments. For additional information on these U.K. natural gas contracts, see "Fair Value Estimates" on page 37.

At December 31, 2006 and 2005, we had no open derivative contracts related to our oil and natural gas production and therefore remained substantially exposed to market prices of commodities. In 2004, we reduced our exposure to market prices of commodities on 26 percent of crude oil production and 7 percent of natural gas production. We continue to evaluate the commodity price risks related to our production and may enter into commodity derivative instruments when it is deemed advantageous. As a particular but not exclusive example, we may elect to use commodity derivative instruments to achieve minimum price levels on some portion of our production to support capital or acquisition funding requirements.

RM&T Segment

We do not attempt to qualify commodity derivative instruments used in our RM&T operations for hedge accounting. As a result, we recognize in net income all changes in the fair value of derivatives used in our RM&T operations. Pretax derivative gains and losses included in RM&T segment income for each of the last three years are summarized in the following table:

Strategy (In millions)	**2006**	**2005**	**2004**
Mitigate price risk	**$ 204**	$ (57)	$ (106)
Protect carrying values of excess inventories	**200**	(118)	(98)
Protect margins associated with fixed price sales	**(4)**	18	8
Protect crack spread values		(81)	(76)
Subtotal, non-trading activities	**400**	(238)	(272)
Trading activities	**1**	(87)	8
Total net derivative gains (losses)	**$ 401**	$ (325)	$ (264)

Derivatives used in non-trading activities have an underlying physical commodity transaction. Since the majority of RM&T segment derivative contracts are for the sale of commodities, derivative losses generally occur when market prices increase and typically are offset by gains on the underlying physical commodity transactions. Conversely, derivative gains generally occur when market prices decrease and are typically offset by losses on the underlying physical commodity transactions. The income effect related to derivatives and the income effect related to the underlying physical transactions may not necessarily be recognized in net income in the same period because we do not attempt to qualify these commodity derivative instruments for hedge accounting. The year-to-year change in the net impact of derivatives primarily reflects changes in market conditions.

Other Commodity Related Risks

We are impacted by basis risk, caused by factors that affect the relationship between commodity futures prices reflected in derivative commodity instruments and the cash market price of the underlying commodity. Natural gas transaction prices are frequently based on industry reference prices that may vary from prices experienced in local markets. For example, New York Mercantile Exchange ("NYMEX") contracts for natural gas are priced at Louisiana's Henry Hub, while the underlying quantities of natural gas may be produced and sold in the western United States at prices that do not move in strict correlation with NYMEX prices. If commodity price changes in one region are not reflected in other regions, derivative commodity instruments may no longer provide the expected hedge, resulting in increased exposure to basis risk. These regional price differences could yield favorable or unfavorable results. Over-the-counter transactions are being used to manage exposure to a portion of basis risk.

We are impacted by liquidity risk, caused by timing delays in liquidating contract positions due to a potential inability to identify a counterparty willing to accept an offsetting position. Due to the large number of active participants, liquidity risk exposure is relatively low for exchange-traded transactions.

Interest Rate Risk

We are impacted by interest rate fluctuations which affect the fair value of certain financial instruments. A sensitivity analysis of the projected incremental effect of a hypothetical 10 percent decrease in interest rates is provided in the following table:

(In millions)

	December 31, 2006		December 31, 2005	
	Fair Value[b]	**Incremental Increase in Fair Value[c]**	**Fair Value[b]**	**Incremental Increase in Fair Value[c]**
Financial assets (liabilities)[a]:				
Investments and long-term receivables	**$ 461**	**$**	$ 268	$
Interest rate swap agreements[d]	**$ (22)**	**$ 9**	$ (30)	$ 14
Long-term debt[d][e]	**$ (3,729)**	**$ (132)**	$ (4,354)	$ (152)

(a) Fair values of cash and cash equivalents, receivables, notes payable, commercial paper, 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 carrying value of these instruments.

(c) For long-term debt, this assumes a 10 percent decrease in the weighted average yield to maturity of our long-term debt at December 31, 2006 and 2005. For interest rate swap agreements, this assumes a 10 percent decrease in the effective swap rate at December 31, 2006 and 2005.

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

(e) Includes amounts due within one year.

At December 31, 2006 and 2005, our portfolio of long-term debt was substantially comprised of fixed rate instruments. Therefore, the fair value of the portfolio is relatively sensitive to the effects of interest rate fluctuations. This sensitivity is illustrated by the $132 million increase in the fair value of long-term debt at December 31, 2006, assuming a hypothetical 10 percent decrease in interest rates. However, our sensitivity to interest rate declines and corresponding increases in the fair value of our debt portfolio unfavorably affect our results of operations and cash flows when we elect to repurchase or otherwise retire fixed-rate debt at prices above carrying value.

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 fixed and floating interest rate mix of the debt 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, 2006:

(Dollars in millions)

Floating Rate to be Paid	**Fixed Rate to be Received**	**Notional Amount**	**Swap Maturity**	**Fair Value**
Six Month LIBOR +1.935%	5.375%	$ 450	2007	$ (4)
Six Month LIBOR +3.285%	6.850%	$ 400	2008	$ (8)
Six Month LIBOR +2.142%	6.125%	$ 200	2012	$ (10)

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 the foreign currency markets by locking in foreign currency rates. At December 31, 2006, the following currency derivatives were outstanding. All contracts currently qualify for hedge accounting.

(Dollars in millions)

	Period		Notional Amount		Forward Rate[(a)]	Fair Value[(b)]	
Foreign Currency Rate Forwards:							
Euro	July 2007	November 2008	$	51	1.255[(c)]	$	3
Kroner (Norway)	January 2007	October 2009	$	127	6.213[(d)]	$	

(a) Rates shown are weighted average all-in 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 effect on foreign currency forward contracts of a hypothetical 10 percent change to exchange rates at December 31, 2006, would be approximately $14 million.

Credit Risk

We are exposed to significant credit risk from United States Steel arising from the Separation. That exposure is discussed in Management's Discussion and Analysis of Financial Condition and Results of Operations   Obligations Associated with the Separation of United States Steel.

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 hedging programs may differ materially from those discussed in the forward-looking statements.

Item 8. Financial Statements and Supplementary Data

MARATHON OIL CORPORATION

Index to 2006 Consolidated Financial Statements and Supplementary Data

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 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 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, 2006.

Marathon's management assessment of the effectiveness of Marathon's internal control over financial reporting as of December 31, 2006 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.	Janet F. Clark
President and	*Executive Vice President*
Chief Executive Officer	*and Chief Financial Officer*

Report of Independent Registered Public Accounting Firm

To the Stockholders of Marathon Oil Corporation:

We have completed integrated audits of Marathon Oil Corporation's consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

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 at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes 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. We believe that our audits provide a reasonable basis for our opinion.

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.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Control over Financial Reporting, appearing herein, that the Company maintained effective internal control over financial reporting as of December 31, 2006 based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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

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

PricewaterhouseCoopers LLP
Houston, Texas
February 28, 2007

Consolidated Statement of Income

(Dollars in millions except per share data)

	2006	2005	2004
Revenues and other income:			
Sales and other operating revenues (including consumer excise taxes)	**$ 57,973**	$ 48,948	$ 39,172
Revenues from matching buy/sell transactions	**5,457**	12,636	9,242
Sales to related parties	**1,466**	1,402	1,051
Income from equity method investments	**391**	265	167
Net gains on disposal of assets	**77**	57	36
Gain on ownership change in Marathon Petroleum Company LLC			2
Other income	**85**	37	100
Total revenues and other income	**65,449**	63,345	49,770
Costs and expenses:			
Cost of revenues (excludes items shown below)	**42,415**	37,806	30,700
Purchases related to matching buy/sell transactions	**5,396**	12,364	9,050
Purchases from related parties	**210**	225	202
Consumer excise taxes	**4,979**	4,715	4,463
Depreciation, depletion and amortization	**1,518**	1,303	1,178
Selling, general and administrative expenses	**1,228**	1,155	1,021
Other taxes	**371**	318	282
Exploration expenses	**365**	217	158
Total costs and expenses	**56,482**	58,103	47,054
Income from operations	**8,967**	5,242	2,716
Net interest and other financing costs (income)	**(37)**	146	162
Loss on early extinguishment of debt	**35**		
Minority interests in income (loss) of:			
Marathon Petroleum Company LLC		384	532
Equatorial Guinea LNG Holdings Limited	**(10)**	(8)	(7)
Income from continuing operations before income taxes	**8,979**	4,720	2,029
Provision for income taxes	**4,022**	1,714	735
Income from continuing operations	**4,957**	3,006	1,294
Discontinued operations	**277**	45	(33)
Income before cumulative effect of change in accounting principle	**5,234**	3,051	1,261
Cumulative effect of change in accounting principle		(19)	
Net income	**$ 5,234**	$ 3,032	$ 1,261
Per Share Data			
Basic:			
Income from continuing operations	**$ 13.85**	$ 8.44	$ 3.85
Net income	**$ 14.62**	$ 8.52	$ 3.75
Diluted:			
Income from continuing operations	**$ 13.73**	$ 8.37	$ 3.83
Net income	**$ 14.50**	$ 8.44	$ 3.73

(Dollars in millions except per share data)

	2006	2005	2004

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

Consolidated Balance Sheet

(Dollars in millions, except per share data)

December 31	2006	2005
Assets		
Current assets:		
Cash and cash equivalents	**$ 2,585**	$ 2,617
Receivables, less allowance for doubtful accounts of $3 and $3	**4,114**	3,476
Receivables from United States Steel	**32**	20
Receivables from related parties	**63**	38
Inventories	**3,173**	3,041
Other current assets	**129**	191
Total current assets	**10,096**	9,383
Investments and long-term receivables, less allowance for doubtful accounts of $9 and $10	**1,887**	1,864
Receivables from United States Steel	**498**	532
Property, plant and equipment, net	**16,653**	15,011
Goodwill	**1,398**	1,307
Intangible assets, net	**180**	200
Other noncurrent assets	**119**	201
Total assets	**$ 30,831**	$ 28,498
Liabilities		
Current liabilities:		
Accounts payable	**$ 5,586**	$ 5,353
Consideration payable under Libya re-entry agreement		732
Payable to United States Steel	**13**	
Payables to related parties	**264**	82
Payroll and benefits payable	**409**	344
Accrued taxes	**598**	782
Deferred income taxes	**631**	450
Accrued interest	**89**	96
Long-term debt due within one year	**471**	315
Total current liabilities	**8,061**	8,154
Long-term debt	**3,061**	3,698
Deferred income taxes	**1,897**	2,030
Defined benefit postretirement plan obligations	**1,245**	1,251
Asset retirement obligations	**1,044**	711
Payable to United States Steel	**7**	6
Deferred credits and other liabilities	**391**	508
Total liabilities	**15,706**	16,358
Minority interests in Equatorial Guinea LNG Holdings Limited	**518**	435
Commitments and contingencies		
Stockholders' Equity		
Common stock issued 367,851,558 and 366,925,852 shares (par value $1 per share, 550,000,000 shares authorized)	**368**	367
Common stock held in treasury, at cost 20,080,670 and 179,977 shares	**(1,638)**	(8)
Additional paid-in capital	**5,152**	5,111
Retained earnings	**11,093**	6,406
Accumulated other comprehensive loss	**(368)**	(151)
Unearned compensation		(20)

(Dollars in millions, except per share data)

December 31	2006	2005
Total stockholders' equity	**14,607**	11,705
Total liabilities and stockholders' equity	**$ 30,831**	$ 28,498

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

Consolidated Statement of Cash Flows

(Dollars in millions)

	2006	2005	2004
Increase (decrease) in cash and cash equivalents			
Operating activities:			
Net income	**$ 5,234**	$ 3,032	$ 1,261
Adjustments to reconcile net income to net cash provided from operating activities:			
Loss on early extinguishment of debt	**35**		
Cumulative effect of change in accounting principle		19	
Income from discontinued operations	**(277)**	(45)	33
Deferred income taxes	**268**	(205)	(62)
Minority interests in income (loss) of subsidiaries	**(10)**	376	525
Depreciation, depletion and amortization	**1,518**	1,303	1,178
Pension and other postretirement benefits, net	**(404)**	71	82
Exploratory dry well costs and unproved property impairments	**166**	111	68
Net gains on disposal of assets	**(77)**	(57)	(36)
Equity method investments, net	**(200)**	(65)	(15)
Changes in the fair value of long-term U.K. natural gas contracts	**(454)**	386	99
Changes in:			
Current receivables	**(535)**	(1,164)	(691)
Inventories	**(133)**	(150)	(40)
Current accounts payable and accrued expenses	**237**	1,065	1,197
All other, net	**50**	(22)	137
Net cash provided from continuing operations	**5,418**	4,655	3,736
Net cash provided from discontinued operations	**70**	83	30
Net cash provided from operating activities	**5,488**	4,738	3,766
Investing activities:			
Capital expenditures	**(3,433)**	(2,796)	(2,141)
Acquisitions	**(741)**	(506)	
Disposal of discontinued operations	**832**		
Proceeds from sale of minority interests in Equatorial Guinea LNG Holdings Limited		163	
Disposal of assets	**134**	131	76
Restricted cash deposits	**(19)**	(54)	(42)
Restricted cash withdrawals	**43**	41	34
Investments loans and advances	**(17)**	(28)	(160)
repayments of loans and advances	**298**	15	15
Investing activities of discontinued operations	**(45)**	(94)	(106)
All other, net	**(7)**	1	
Net cash used in investing activities	**(2,955)**	(3,127)	(2,324)
Financing activities:			
Payment of debt assumed in acquisition		(1,920)	
Debt issuance costs			(4)
Other debt repayments	**(501)**	(8)	(259)
Issuance of common stock	**50**	78	1,043
Purchases of common stock	**(1,698)**		
Excess tax benefits from stock-based compensation arrangements	**35**		
Dividends paid	**(547)**	(436)	(348)
Contributions from minority shareholders of Equatorial Guinea LNG Holdings Limited	**80**	213	95
Distributions to minority shareholder of Marathon Petroleum Company LLC		(272)	

(Dollars in millions)

	2006	2005	2004
Net cash provided from (used in) financing activities	**(2,581)**	(2,345)	527
Effect of exchange rate changes on cash	**16**	(18)	4
Net increase (decrease) in cash and cash equivalents	**(32)**	(752)	1,973
Cash and cash equivalents at beginning of year	**2,617**	3,369	1,396
Cash and cash equivalents at end of year	**$ 2,585**	$ 2,617	$ 3,369

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

Consolidated Statement of Stockholders' Equity

(Dollars in millions, except per share data)	Stockholders' Equity			Shares in thousands		
	2006	**2005**	**2004**	**2006**	**2005**	**2004**
Common stock issued						
Balance at beginning of year	**$ 367**	$ 347	$ 312	**366,926**	346,718	312,166
Issuances[a]	**1**	20	35	**926**	20,208	34,552
Balance at end of year	**$ 368**	$ 367	$ 347	**367,852**	366,926	346,718
Common stock held in treasury, at cost						
Balance at beginning of year	**$ (8)**	$ (1)	$ (46)	**(180)**	(35)	(1,744)
Repurchases	**(1,698)**	(7)	(4)	**(20,745)**	(10)	(129)
Reissuances for employee stock plans	**68**		49	**844**	(135)	1,838
Balance at end of year	**$ (1,638)**	$ (8)	$ (1)	**(20,081)**	(180)	(35)
				Comprehensive Income		
				2006	**2005**	**2004**
Additional paid-in capital						
Balance at beginning of year	**$ 5,111**	$ 4,028	$ 3,033			
Stock issuances[a]	**(7)**	1,048	983			
Stock-based compensation expense	**48**	35	12			
Balance at end of year	**$ 5,152**	$ 5,111	$ 4,028			
Unearned compensation						
Balance at beginning of year	**$ (20)**	$ (9)	$ (9)			
Change in accounting principle	**20**					
Changes during year		(11)				
Balance at end of year	**$**	$ (20)	$ (9)			
Retained earnings						
Balance at beginning of year	**$ 6,406**	$ 3,810	$ 2,897			
Net income	**5,234**	3,032	1,261	**$ 5,234**	$ 3,032	$ 1,261
Dividends paid (per share: $1.53 in 2006, $1.22 in 2005 and $1.03 in 2004)	**(547)**	(436)	(348)			
Balance at end of year	**$ 11,093**	$ 6,406	$ 3,810			
Accumulated other comprehensive loss						
Minimum pension liability adjustments:						
Balance at beginning of year	**$ (141)**	$ (71)	$ (93)			
Changes during year, net of tax of $74, $42 and $3	**114**	(70)	22	**114**	(70)	22
Reclassification to defined benefit postretirement plans	**27**					

	Stockholders' Equity			Shares in thousands		
Balance at end of year	**$**	$	$ (71)			
		(141)				
Defined benefit postretirement plans:						
Balance at beginning of year	**$**	$	$			
Reclassification from minimum pension liability adjustments	**(27)**					
Change in accounting principle, net of tax of $289	**(348)**					
Balance at end of year	**$ (375)**	$	$			
Deferred gains (losses) on derivative instruments:						
Balance at beginning of year	**$ (5)**	$ 12	$ (15)			
Reclassification of the cumulative effect adjustment into net income, net of tax of $, $ and $1	**(2)**	(2)	(3)	**(2)**	(2)	(3)
Changes in fair value, net of tax of $1, $3 and $20	**4**	(15)	(82)	**4**	(15)	(82)
Reclassification to net income, net of tax of $, $ and $30	**1**		112	**1**		112
Balance at end of year	**$ (2)**	$ (5)	$ 12			
Other:						
Balance at beginning of year	**$ (5)**	$ (5)	$ (4)			
Changes during year, net of tax of $8, $ and $	**14**		(1)	**9**		(1)
Balance at end of year	**$ 9**	$ (5)	$ (5)			
Total at end of year	**$ (368)**	$ (151)	$ (64)			
Comprehensive income				**$ 5,360**	$ 2,945	$ 1,309
Total stockholders' equity	**$ 14,607**	$ 11,705	$ 8,111			

[(a)] On March 31, 2004, Marathon issued 34,500,000 shares of its common stock at the offering price of $30 per share and recorded net proceeds of $1.004 billion. On June 30, 2005, in connection with the acquisition of Ashland Inc.'s minority interest in Marathon Petroleum Company LLC, Marathon distributed 17,538,815 shares of its common stock valued at $54.45 per share to Ashland's shareholders.

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

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 crude oil and natural gas; 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 the businesses comprising Marathon.

Prior to June 30, 2005, Marathon owned a 62 percent interest in Marathon Petroleum Company LLC ("MPC"). After Marathon acquired the remaining 38 percent interest as described in Note 6, MPC became a wholly owned subsidiary of Marathon. The accounts of MPC are consolidated in these financial statements for all periods presented and the applicable minority interest has been recognized for activity prior to the acquisition date.

Investments in unincorporated oil and natural gas joint ventures and undivided interests in certain pipelines, natural gas processing plants and LNG tankers are consolidated on a pro rata basis.

Investments in variable interest entities ("VIEs") for which Marathon is the primary beneficiary are consolidated.

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. Differences in the basis of the investments and the separate net asset values 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. Income from equity method investments represents Marathon's proportionate share of net income generated by the equity method investees.

Gains or losses from a change in ownership of a consolidated subsidiary or an unconsolidated investee are recognized in net income in the period of change.

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.

Income per common share Basic income per share is calculated based on the weighted average number of common shares outstanding. 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 three reportable operating segments:

Exploration and Production ("E&P") explores for, produces and markets crude oil and natural gas on a worldwide basis;

Refining, Marketing and Transportation ("RM&T") refines, markets and transports crude oil and petroleum products, primarily in the Midwest, the upper Great Plains and southeastern 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") 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 segment 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 segment 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 accounted for as derivative instruments, gains and losses on ownership changes in subsidiaries 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.

Marathon recognizes revenues from the production of oil and natural gas when title is transferred. 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, production volumes may be stored as inventory and sold at a later time. Royalties on the production of oil and natural gas 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.

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.

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 the current imbalance situation.

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 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. An inventory market valuation reserve results when the recorded LIFO cost basis of crude oil and refined products inventories exceeds net realizable value. The reserve is decreased when market prices increase and inventories turn over and is increased when market prices decrease. Changes in the inventory market valuation reserve result in non-cash charges or credits to costs and expenses.

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 values 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 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 values 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 that delivery location to be considered derivative instruments. Other physical contracts that management has chosen not to designate as a normal purchase or normal sale, which can include contracts that involve flash title, are also accounted for as nontraditional derivative instruments.

Investment in marketable securities Management determines the appropriate classification of investments in marketable debt and equity securities at the time of acquisition and re-evaluates such designation as of each subsequent balance sheet date. Securities classified as "available for sale" are carried at estimated fair value with unrealized gains and losses, net of tax, recorded as a component of accumulated other comprehensive loss. Marathon holds no securities classified as "held to maturity securities" or "trading securities." Realized and unrealized gains and losses are calculated using the specific identification method.

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 by the units-of-production method. Support equipment and other property, plant and equipment are depreciated on a straight line basis over their estimated useful lives.

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 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 values.

Marathon evaluates its unproved property investment and impairs 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.

Property, plant and equipment unrelated to oil and gas producing activities is recorded at cost and depreciated on the straight-line method 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 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 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 the components of the E&P segment have similar economic characteristics and therefore aggregates the components into 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 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 other intangible assets are amortized over their estimated useful lives or the expected lives of the related contracts, as applicable, which range from 2 to 22 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.

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 values of asset retirement obligations are recognized in the period in which they 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.

Effective December 31, 2005, conditional asset retirement obligations for removal and disposal of fire-retardant material from certain refining facilities have 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 and marketing 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 values 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 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.

Pensions and other postretirement benefits Marathon uses a December 31 measurement date for its pension and other postretirement benefit plans.

Stock-based compensation arrangements Marathon adopted Statement of Financial Accounting Standards ("SFAS") No. 123(R), "Share-Based Payment," 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. Prior to adoption of SFAS No. 123 (Revised 2004), "Share-Based Payment," ("SFAS No. 123(R)") on January 1, 2006, the fair values of Marathon's stock-based performance awards were determined in the same manner as restricted stock awards. Under SFAS No. 123(R), on a prospective basis, these awards are required to be valued utilizing an option pricing model. See Note 2 for further information regarding Marathon's adoption of SFAS No. 123(R). No stock-based performance awards have been granted since May 2004.

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 and stock-based performance awards are granted. Compensation expense is recognized over the balance of the vesting period and is adjusted if conditions of the restricted stock award or stock-based performance 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 26 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 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 2006 classifications.

2. New Accounting Standards

SFAS No. 158 In September 2006, the Financial Accounting Standards Board ("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 sheet as of that date. 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 24 for additional disclosures regarding pensions and other postretirement plans required by SFAS No. 158.

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)	$
Investments and long-term receivables	1,893	(6)	1,887
Total assets	31,066	(235)	30,831
Payroll and benefits payable	384	25	409
Defined benefit postretirement plan obligations	870	375	1,245
Long-term deferred income taxes	2,183	(286)	1,897
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 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 all 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.

FIN No. 47 In March 2005, the FASB issued FASB Interpretation ("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 and 2004 is not significantly different than amounts reported. The following summarizes the total amount of the liability for asset retirement obligations as if FIN No. 47 had been applied during all periods presented. The pro forma impact of the adoption of FIN No. 47 on these unaudited pro forma liability amounts has been measured using the information, assumptions and interest rates used to measure the obligation recognized upon adoption of FIN No. 47.

(In millions)

December 31, 2003	$ 438
December 31, 2004	527
December 31, 2005	711

(In millions)

SFAS No. 153 Marathon adopted SFAS No. 153, "Exchanges of Nonmonetary Assets an amendment of APB Opinion No. 29," on a prospective basis as of July 1, 2005. This amendment eliminates the APB Opinion No. 29 exception for fair value recognition of nonmonetary exchanges of similar productive assets and replaces it with an exception for exchanges of nonmonetary assets that do not have commercial substance.

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 suspended 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 suspended 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 15.

FSP No. FAS 109-1 Effective December 21, 2004, Marathon adopted FSP No. FAS 109-1, "Application of FASB Statement No. 109, *Accounting for Income Taxes*, to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004." FSP No. FAS 109-1 states the deduction, signed into law on October 22, 2004, of up to 9 percent (when fully phased-in) of the lesser of (1) "qualified production activities income," as defined in the Act, or (2) taxable income (after the deduction for the utilization of any net operating loss carryforwards) should be accounted for as a special deduction in accordance with SFAS No. 109. Accordingly, Marathon treats the deduction related to production activities income as a special deduction in the years taken.

FSP No. FAS 106-2 Effective July 1, 2004, Marathon adopted FSP No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003." FSP No. FAS 106-2 includes guidance on recognizing the effects of the new legislation under the various conditions surrounding the assessment of "actuarial equivalence." Marathon has determined, based on available regulatory guidance, that the postretirement plans' prescription drug benefits are actuarially equivalent to the Medicare "Part D" benefit under the Act. The subsidy-related reduction at July 1, 2004 in the accumulated postretirement benefit obligation for the Marathon postretirement benefit plans was $93 million. The combined favorable pretax effect of the subsidy-related reduction for 2004 on the measurement of the net periodic postretirement benefit cost related to service cost, interest cost and actuarial gain amortization was $7 million.

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.

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 U.S. federal tax returns under the Tax Sharing Agreement was made in January 2007.

Amounts receivable from or payable to United States Steel arising from the Separation As previously discussed, Marathon remains primarily obligated for certain financings for which United States Steel has assumed responsibility for repayment under the terms of the Separation. When United States Steel makes payments on the principal of these financings, both the receivable from United States Steel and the obligation are reduced.

At December 31, 2006 and 2005, amounts receivable from or payable to United States Steel included in the consolidated balance sheets were as follows:

(In millions) **December 31**	**2006**	2005
Receivables related to debt and other obligations for which United States Steel has assumed responsibility for repayment:		
Current	**$ 32**	$ 20
Noncurrent	**498**	532
Current payable for interest related to tax settlements	**13**	
Noncurrent reimbursements payable under nonqualified defined benefit postretirement plans	**7**	6

Marathon remains primarily obligated for $34 million of operating lease obligations assumed by United States Steel, of which $31 million has been assumed by third parties that purchased plants and operations divested by United States Steel.

In addition, Marathon remains contingently liable for certain obligations of United States Steel. See Note 30 for further information regarding these guarantees.

4. Variable Interest Entities

Equatorial Guinea LNG Holdings Limited ("EGHoldings"), in which Marathon holds a 60 percent interest and which was formed for the purpose of constructing and operating an LNG production facility, is a VIE that is consolidated. As of December 31, 2006, total expenditures of $1.363 billion related to the LNG production facility, including $1.300 billion of capital expenditures, have been incurred. 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, 2006, Marathon had contributed $11 million to The Andersons Marathon Ethanol LLC.

5. Related Party Transactions

Related parties during 2006, 2005 and 2004 include:

- Sociedad Nacional de Gas de Guinea Ecuatorial ("SONAGAS"), which has held a 25 percent ownership interest in EGHoldings, a consolidated subsidiary, 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 MPC, a consolidated subsidiary, until June 30, 2005; and
- Equity method investees. See "Principal Unconsolidated Investees" on page F-42 for major investees.

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

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

	2006	**2005**	**2004**

(In millions)

Equity method investees:			
PTC	**$ 1,420**	$ 1,205	$ 715
Centennial Pipeline LLC ("Centennial")	**28**	47	49
Other equity method investees	**18**	18	13
Ashland		132	274
Total	**$ 1,466**	$ 1,402	$ 1,051

Purchases from related parties were as follows:

(In millions)	**2006**	**2005**	**2004**
Equity method investees:			
LOOP LLC	**$ 54**	$ 49	$ 44
Centennial	**53**	73	56
Other equity method investees	**103**	91	80
Ashland		12	22
Total	**$ 210**	$ 225	$ 202

Current receivables from related parties were as follows:

(In millions)

December 31	2006	2005
Equity method investees:		
PTC	**$ 41**	$ 34
Other equity method investees	**9**	4
Other related parties	**13**	
Total	**$ 63**	$ 38

Payables to related parties were as follows:

(In millions)

December 31	2006	2005
SONAGAS	**$ 229**	$
GEPetrol		57
Equity method investees:		
Alba Plant LLC	**15**	14
Other equity method investees	**17**	11
Other related parties	**3**	
Total	**$ 264**	$ 82

MPC had a $190 million uncommitted revolving credit agreement with Ashland that terminated in March 2005. Interest paid to Ashland for borrowings under this agreement was less than $1 million in each of 2005 and 2004.

Cash of $234 million held in escrow for future capital contributions from SONAGAS to EGHoldings is classified as restricted cash and is included in investments and long-term receivables as of December 31, 2006.

6. Acquisitions

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 (the "Acquisition"), MAP is now wholly owned by Marathon and its name was changed to Marathon Petroleum Company LLC ("MPC") 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 total consideration, including debt assumed, 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	75
Transaction-related costs	10
Purchase price	2,438
Assumption of debt[(c)]	1,920
Total consideration including debt assumption[(d)]	$ 4,358

(In millions)

(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.

(a) Ashland shareholders received 17.539 million shares valued at $54.45 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.

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

(a) 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. During 2006, an additional $17 million was included in the purchase price for such amounts.

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
- 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
Investments and long-term receivables		484
Property, plant and equipment		2,671
Goodwill		853
Intangible assets		112
Other noncurrent assets		8
Total assets acquired	$	7,620
Current liabilities:		
Notes payable	$	1,920
Deferred income taxes		669
Other current liabilities		1,686
Total current liabilities assumed		4,275
Long-term debt		16
Deferred income taxes		374
Defined benefit postretirement plan obligations		470
Other liabilities		47
Total liabilities assumed	$	5,182
Net assets acquired	$	2,438

The goodwill arising from the purchase price allocation was $853 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 include 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.

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 and the re-entry to the Libya concessions 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)

		2005		2004
Revenues and other income	$	65,614	$	50,670
Income from continuing operations		3,315		1,596
Net income		3,341		1,563
Per share data:				
Income from continuing operations basic	$	9.09	$	4.51
Income from continuing operations diluted	$	9.01	$	4.49
Net income basic	$	9.16	$	4.42
Net income diluted	$	9.08	$	4.39

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. The final adjustment to the sales price is expected to be made in 2007 and could affect the reported gain.

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, $325 million and $133 million for 2006, 2005, and 2004. Pretax income from discontinued operations was $45 million and $61 million for 2006 and 2005. There was a pretax loss from discontinued operations of $45 million in 2004.

8. Income per Common Share

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

(Dollars in millions, except per share data)	2006 Basic	2006 Diluted	2005 Basic	2005 Diluted	2004 Basic	2004 Diluted
Income from continuing operations	**$ 4,957**	**$ 4,957**	$ 3,006	$ 3,006	$ 1,294	$ 1,294
Discontinued operations	**277**	**277**	45	45	(33)	(33)
Cumulative effect of change in accounting principle			(19)	(19)		
Net income	**$ 5,234**	**$ 5,234**	$ 3,032	$ 3,032	$ 1,261	$ 1,261
Weighted average common shares outstanding	**357,911**	**357,911**	356,003	356,003	336,485	336,485
Effect of dilutive securities		**3,116**		3,078		1,768
Weighted average common shares, including dilutive effect	**357,911**	**361,027**	356,003	359,081	336,485	338,253
Per share:						
Income from continuing operations	**$ 13.85**	**$ 13.73**	$ 8.44	$ 8.37	$ 3.85	$ 3.83
Discontinued operations	**$ 0.77**	**$ 0.77**	$ 0.13	$ 0.12	$ (0.10)	$ (0.10)
Cumulative effect of change in accounting principle	**$**	**$**	$ (0.05)	$ (0.05)	$	$
Net income	**$ 14.62**	**$ 14.50**	$ 8.52	$ 8.44	$ 3.75	$ 3.73

9. Segment Information

Revenues by product line were:

(In millions)	2006	2005	2004
Refined products	**$ 45,511**	$ 40,040	$ 29,780
Merchandise	**2,871**	2,689	2,489
Liquid hydrocarbons	**12,531**	16,352	13,727
Natural gas	**3,742**	3,675	3,266
Transportation and other	**241**	230	203
Total	**$ 64,896**	$ 62,986	$ 49,465

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

(In millions)	2006	2005	2004

(In millions)	2006	2005	2004
Refined products	**$ 645**	$ 1,817	$ 1,226
Liquid hydrocarbons	**4,812**	10,819	8,016
Total	**$ 5,457**	$ 12,636	$ 9,242

Effective January 1, 2006, Marathon revised its measure of segment income to include the effects of minority interests and income taxes related to the segments to facilitate comparison of segment results with Marathon's peers. In addition, the results of activities primarily associated with the marketing of the Company's equity natural gas production, which had been presented as part of the IG segment prior to 2006, are now included in the E&P segment as those activities are aligned with E&P operations. Segment information for all periods presented reflects these changes.

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.

(In millions)	Exploration and Production	Refining, Marketing and Transportation	Integrated Gas	Total
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 subsidiaries			**(10)**	**(10)**
Income tax provision[(b)]	**2,371**	**1,642**	**8**	**4,021**
Capital expenditures[(c)]	**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)]	1,366	841	571	2,778
2004				
Revenues:				
Customer	$ 5,888	$ 42,435	$ 190	$ 48,513
Intersegment[(a)]	516	152		668
Related parties	8	1,043		1,051
Segment revenues	6,412	43,630	190	50,232
Elimination of intersegment revenues	(516)	(152)		(668)
Loss on long-term U.K. natural gas contracts	(99)			(99)
Total revenues	$ 5,797	$ 43,478	$ 190	$ 49,465
Segment income	$ 1,090	$ 568	$ 37	$ 1,695
Income from equity method investments	17	81	69	167
Depreciation, depletion and amortization[(b)]	724	416	7	1,147

(In millions)	Exploration and Production	Refining, Marketing and Transportation	Integrated Gas	Total
Minority interests in income (loss) of subsidiaries[(b)]		539	(7)	532
Income tax provision[(b)]	606	301	19	926
Capital expenditures[(c)]	840	794	488	2,122

(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.

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

(In millions)	2006	2005	2004
Segment income	**$ 4,814**	$ 3,570	$ 1,695
Items not allocated to segments, net of income taxes:			
Corporate and other unallocated items	**(212)**	(377)	(327)
Gain (loss) on long-term U.K. natural gas contracts	**232**	(223)	(57)
Discontinued operations	**277**	45	(33)
Gain on disposition of Syria interest	**31**		
Deferred income taxes tax legislation changes	**21**	15	
&#15 0; other adjustments[a]	**93**		
Loss on early extinguishment of debt	**(22)**		
Gain on sale of minority interests in EGHoldings		21	
Corporate insurance adjustment			(17)
Cumulative effect of change in accounting principle		(19)	
Net income	**$ 5,234**	$ 3,032	$ 1,261

(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)	2006	2005	2004
United States	**$ 59,723**	$ 60,242	$ 47,354
International	**5,173**	2,744	2,111
Total	**$ 64,896**	$ 62,986	$ 49,465

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

(In millions)	2006	2005
United States	**$ 11,401**	$ 10,143
Equatorial Guinea	**3,157**	3,018
Other international	**3,668**	3,510
Total	**$ 18,226**	$ 16,671

10. Other Items

Net interest and other financing costs (income)

(In millions)	2006	2005	2004
Interest and other financial income:			
Interest income	**$ 129**	$ 77	$ 44
Foreign currency gains (losses)	**16**	(17)	9

(In millions)

	2006	2005	2004
Total	**145**	60	53
Interest and other financing costs:			
Interest incurred[(a)]	**245**	257	262
(Income) loss from interest rate swaps	**16**		(24)
Interest capitalized	**(152)**	(83)	(48)
Net interest expense	**109**	174	190
Net interest expense (income) on tax issues	**(11)**	22	12
Other	**10**	10	13
Total	**108**	206	215
Net interest and other financing costs (income)	**$ (37)**	$ 146	$ 162

(a) Excludes $33 million, $34 million and $40 million paid by United States Steel in 2006, 2005 and 2004 on assumed debt.

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

(In millions)

	2006	2005	2004
Net interest and other financing costs	**$ 16**	$ (17)	$ 9
Provision for income taxes	**(22)**	24	(15)
Aggregate foreign currency gains (losses)	**$ (6)**	$ 7	$ (6)

11. Income Taxes

Income tax provisions (benefits) were:

(In millions)	2006			2005			2004		
	Current	**Deferred**	**Total**	**Current**	**Deferred**	**Total**	**Current**	**Deferred**	**Total**
Federal	**$ 1,579**	**$ 72**	**$ 1,651**	$ 1,225	$ 14	$ 1,239	$ 476	$ (20)	$ 456
State and local	**230**	**30**	**260**	171	12	183	47	1	48
Foreign	**1,945**	**166**	**2,111**	523	(231)	292	274	(43)	231
Total	**$ 3,754**	**$ 268**	**$ 4,022**	$ 1,919	$ (205)	$ 1,714	$ 797	$ (62)	$ 735

A reconciliation of the federal statutory tax rate (35 percent) applied to income from continuing operations before income taxes to the provision for income taxes follows:

(In millions)	**2006**	**2005**	**2004**
Statutory rate applied to income from continuing operations before income taxes	**$ 3,143**	$ 1,652	$ 710
Effects of foreign operations, including foreign tax credits[(a)]	**888**	(39)	10
State and local income taxes net of federal income tax effects	**170**	119	32
Credits other than foreign tax credits	**(2)**	(2)	(2)
Domestic manufacturing deduction[(b)]	**(47)**	(39)	
Excess capital losses generated (utilized)		23	(4)
Effects of partially owned companies	**(6)**	(4)	(3)
Adjustment of prior years' federal income taxes[(c)]	**(119)**	10	(8)
Other	**(5)**	(6)	
Provision for income taxes	**$ 4,022**	$ 1,714	$ 735

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

(b) See Note 2 regarding Marathon's adoption of FSP No. FAS 109-1. Marathon has treated the deduction, equal to 3 percent of "qualified production activities income" under the American Jobs Creation Act of 2004, as a special deduction beginning in 2005.

(c) The 2006 adjustment of prior years' federal income taxes is primarily related to a $93 million credit recorded in the fourth quarter of 2006 as a result of a deferred tax 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.

Deferred tax assets and liabilities resulted from the following:

(In millions) December 31	**2006**	**2005**
Deferred tax assets:		
Employee benefits	**$ 730**	$ 622
Capital loss carryforwards[(a)]		79
Operating loss carryforwards[(b)]	**1,016**	754
Derivative instruments	**81**	181
Foreign tax credits[(c)]	**527**	123
Other	**200**	380
Valuation allowances		
Federal[(a)(d)]	**(19)**	(120)

(In millions)

December 31	2006	2005
State[b]	**(59)**	(72)
Foreign[e]	**(611)**	(435)
Total deferred tax assets	**1,865**	1,512
Deferred tax liabilities:		
Property, plant and equipment	**2,951**	2,867
Inventories	**708**	762
Investments in subsidiaries and affiliates	**552**	93
Other	**100**	108
Total deferred tax liabilities	**4,311**	3,830
Net deferred tax liabilities	**$ 2,446**	$ 2,318

(a) Capital loss carryforwards were utilized in conjunction with the sale of Marathon's Russian oil exploration and production businesses in June 2006 as discussed in Note 7. The reversal of the related valuation allowance reduced income taxes attributable to discontinued operations by $79 million.

(b) For 2006, foreign operating loss carryforwards primarily include $684 million for Norway regular income tax, $1.006 billion for Norway special petroleum tax and $250 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 and expire in 2007 through 2019. State operating loss carryforwards of $1.352 billion expire in 2007 through 2021. The state operating loss carryforwards primarily relate the period prior to the Separation and are offset by valuation allowances.

(c) Marathon expects to generate sufficient future taxable income to realize these credits. The 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.

(d) Federal valuation allowances increased by $63 million in 2005 and decreased by $10 million in 2004. The 2005 increase reflected 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.

(e) Foreign valuation allowances increased by $176 million, $70 million and $82 million in 2006, 2005 and 2004 primarily as a result of net operating loss carryforwards generated in those years in Norway, Angola and several other jurisdictions.

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

(In millions) December 31	2006	2005
Assets:		
Other current assets	**$ 4**	$ 14
Other noncurrent assets	**78**	148
Liabilities:		
Current deferred income taxes	**631**	450
Noncurrent deferred income taxes	**1,897**	2,030
Net deferred tax liabilities	**$ 2,446**	$ 2,318

Marathon is continuously undergoing examination of its federal income tax returns by the Internal Revenue Service. Audits of the Company's 1998 through 2003 income tax returns have been completed and agreed upon by all parties. A $46 million refund was received from the 1998 through 2001 audit, $35 million of which was paid to United States Steel in accordance with the tax sharing agreement discussed in Note 3. The audit for tax years 2004 and 2005 commenced in May 2006. Marathon believes it has made adequate provision for federal income taxes and interest which may become payable for years not yet settled. Further, the Company is routinely involved in 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 liabilities.

Pretax income from continuing operations included amounts attributable to foreign sources of $3.570 billion in 2006, $1.061 billion in 2005 and $579 million in 2004.

Undistributed income of certain consolidated foreign subsidiaries at December 31, 2006 amounted to $1.581 billion for which no deferred U.S. income tax provision has been made because Marathon intends to permanently reinvest such income in those foreign operations. If such income was not permanently reinvested, a tax expense of $554 million would have been incurred.

12. Business Transformation

During 2003, Marathon implemented an organizational realignment plan that included streamlining Marathon's business processes and services, realigning reporting relationships to reduce costs across all organizations, consolidating organizations in Houston, Texas and reducing the workforce. During 2004, Marathon entered into two outsourcing agreements to achieve further business process improvements and cost reductions.

During 2004, Marathon recorded $43 million of costs as general and administrative expenses related to these business transformation programs. These charges included employee severance and benefit costs, relocation costs and net benefit plans settlement and curtailment losses.

There were minimal charges to expense during 2005. As of December 31, 2005, no accrual remained related to the business transformation programs. The following table sets forth the significant components and activity in the business transformation programs during 2004.

(In millions)	Accrued January 1	Expense	Noncash Charges	Cash Payments	Accrued December 31
Employee severance and termination benefits	$ 12	$ 15	$	$ 24	$ 3
Net benefit plans settlement and curtailment losses		20	20		
Relocation costs	5	8		11	2
Fixed asset related costs	1			1	
Total	$ 18	$ 43	$ 20	$ 36	$ 5

13. Inventories

December 31	2006	2005

(In millions)

Liquid hydrocarbons and natural gas	**$ 1,136**	$ 1,093
Refined products and merchandise	**1,812**	1,763
Supplies and sundry items	**225**	185
Total (at cost)	**$ 3,173**	$ 3,041

The LIFO method accounted for 90 percent and 92 percent of total inventory value at December 31, 2006 and 2005. Current acquisition costs were estimated to exceed the LIFO inventory values at December 31, 2006 and 2005 by $1.682 billion and $1.535 billion.

14. Investments and Long-Term Receivables

(In millions)

December 31	2006	2005
Equity method investments:		
Alba Plant LLC	**$ 420**	$ 513
Atlantic Methanol Production Company LLC	**257**	258
Pilot Travel Centers LLC	**510**	516
LOOP LLC	**156**	148
Other	**196**	220
Other investments	**34**	5
Recoverable environmental costs receivable	**54**	57
Value-added tax refunds receivable		29
Fair value of derivative assets		14
Deposits of restricted cash	**240**	87
Other receivables	**20**	17
Total	**$ 1,887**	$ 1,864

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

(In millions)

	2006	2005	2004
Income data year:			
Revenues and other income	**$ 11,873**	$ 10,088	$ 7,419
Operating income	**746**	556	434
Net income	**710**	474	330
Balance sheet data December 31:			
Current assets	**$ 817**	$ 645	
Noncurrent assets	**3,637**	3,598	
Current liabilities	**755**	668	
Noncurrent liabilities	**1,119**	1,477	

Marathon's carrying value of its equity method investments is $250 million higher than the underlying net assets of investees. This basis difference is being amortized into net income over the remaining useful lives of the underlying net assets except for $144 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 $191 million in 2006, $200 million in 2005 and $152 million in 2004.

15. Property, Plant and Equipment

(In millions)

December 31	2006	2005
Production	**$ 18,894**	$ 17,262
Refining	**5,238**	4,727
Marketing	**2,015**	1,895
Transportation	**2,173**	1,980
Gas liquefaction	**1,321**	1,067
Other	**585**	464

(In millions)

December 31	2006	2005
Total	**30,226**	27,395
Less accumulated depreciation, depletion and amortization	**13,573**	12,384
Net property, plant and equipment	**$ 16,653**	$ 15,011

Property, plant and equipment includes gross assets acquired under capital leases of $79 million and $78 million at December 31, 2006 and 2005, with related amounts in accumulated depreciation, depletion and amortization of $10 million and $6 million at December 31, 2006 and 2005.

Deferred exploratory well costs were as follows:

(Dollars in millions) December 31	2006	2005	2004
Amounts capitalized less than one year after completion of drilling	**$ 377**	$ 304	$ 284
Amounts capitalized greater than one year after completion of drilling	**93**	59	55
Total deferred exploratory well costs	**$ 470**	$ 363	$ 339
Number of projects with costs capitalized greater than one year after completion of drilling	**3**	2	2

Exploratory well costs capitalized greater than one year after completion of drilling as of December 31, 2006 included $46 million for the Ozona prospect that was primarily incurred in 2001 and 2002, $17 million for the Flathead prospect that was primarily incurred in 2001 and $30 million related to wells in Equatorial Guinea (primarily Corona and Gardenia) that was primarily incurred in 2004. Both Ozona and Flathead are located in the Gulf of Mexico.

Marathon is continuing to evaluate options to develop the Ozona Prospect. Commercial terms were secured in 2005 after protracted negotiations with offset operators to allow this sub-sea well to be tied back to existing oil and gas infrastructure. A sidetrack well was planned for 2006; however, a deepwater rig could not be obtained due to a partner disposition of interest in the prospect and a shortage of deepwater rigs resulting from hurricane damage in 2005 and increased deepwater drilling activity. During 2006, Marathon continued its efforts to advance the Ozona Prospect by reprocessing existing seismic data to optimize the next well location. Marathon has also continued to actively search for rig availability.

Technical evaluations are complete on the Flathead Prospect and commercial evaluations continued in 2006. The drilling of this prospect is delayed due to the shortage of available deepwater rigs. Marathon continues to pursue partnering opportunities with other oil and gas companies with deepwater rigs under contract that will ultimately result in a well being drilled by 2008.

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

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, 2006	**$ 363**	**$ 174**	**$ (27)**	**$ (21)**	**$ (19)**	**$ 470**
Year ended December 31, 2005	339	135	(31)	(80)		363
Year ended December 31, 2004	243	239	(54)	(89)		339

16. Goodwill

The changes in the carrying amount of goodwill for the years ended December 31, 2006 and 2005, were as follows:

(In millions)	Exploration and Production	Refining, Marketing and Transportation	Total
Balance as of December 31, 2004	$ 231	$ 21	$ 252
Goodwill acquired	315	735	1,050
Other		5	5
Balance as of December 31, 2005	546	761	1,307
Adjustments to previously acquired goodwill	(6)	118[(a)]	112
Disposals[(b)]	(21)		(21)
Balance as of December 31, 2006	**$ 519**	**$ 879**	**$ 1,398**

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

(b) Exploration and Production 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.

17. Intangible Assets

Intangible assets were as follows:

(In millions) December 31	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
2006			
Amortized intangible assets:			
Branding agreements	**$ 54**	**$ 20**	**$ 34**
Elba Island delivery rights	**42**	**8**	**34**
Other	**103**	**47**	**56**
Total	**$ 199**	**$ 75**	**$ 124**
Unamortized intangible assets:			
Retail marketing tradenames	**$ 49**	**$**	**$ 49**
Other	**7**		**7**
Total	**$ 56**	**$**	**$ 56**
2005			
Amortized intangible assets:			
Branding agreements	$ 51	$ 16	$ 35
Elba Island delivery rights	42	6	36
Other	96	36	60
Total	$ 189	$ 58	$ 131

(In millions) December 31	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Unamortized intangible assets:			
Retail marketing tradenames	$ 49	$	$ 49
Unrecognized prior service costs and other	20		20
Total	$ 69	$	$ 69

Amortization expense related to intangibles during 2006, 2005 and 2004 totaled $19 million, $16 million and $7 million. Estimated amortization expense for the years 2007-2011 is $16 million, $14 million, $13 million, $12 million and $10 million.

18. Derivative Instruments

The following table sets forth quantitative information by category of derivative instrument at December 31, 2006 and 2005. These amounts are reported on a gross basis by individual derivative instrument.

(In millions)	2006		2005	
December 31	Assets[a]	(Liabilities)[a]	Assets[a]	(Liabilities)[a]
Commodity Instruments				
Fair value hedges [b]:				
Exchange traded commodity futures	$	$ (4)	$ 2	$ (2)
Over-the-counter ("OTC") commodity swaps	20	(15)	66	(2)
Non-hedge designation:				
Exchange-traded commodity futures	$ 301	$ (258)	$ 281	$ (288)
Exchange-traded commodity options	88	(93)	70	(65)
OTC commodity swaps	44	(34)	105	(99)
OTC commodity options	2	(1)	3	(6)
Nontraditional Instruments				
Long-term United Kingdom natural gas contracts [c]	$	$ (60)	$	$ (513)
Physical commodity contracts [d]	46	(64)	71	(62)
Financial Instruments				
Fair value hedges:				
OTC interest rate swaps [e]	$	$ (22)	$	$ (30)
Cash flow hedges[f]:				
OTC foreign currency forwards	3			(2)

(a) The fair value and carrying value of a derivative instrument are the same. The fair values for OTC commodity positions are determined using option-pricing models or dealer quotes. The fair values of exchange-traded commodity positions are based on market quotes derived from major exchanges. The fair values of interest rate and foreign currency swaps are based on dealer quotes. Marathon's consolidated balance sheet is reported on a net basis by brokerage firm, as permitted by master netting agreements.

(b) There was no ineffectiveness associated with fair value hedges for 2006 or 2005 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 between 2007 and 2008.

(c) 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 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.

(d) Certain physical commodity contracts are classified as nontraditional derivative instruments because certain volumes covered by these contracts are physically netted at particular delivery locations. Additionally, 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 accounted for as nontraditional derivative instruments.

(e) The fair value of OTC interest rate swaps excludes accrued interest amounts not yet settled. As of December 31, 2006 and 2005, accrued interest approximated $4 million and $3 million. The net fair value of the OTC interest rate swaps as of December 31, 2006 and 2005 is included in long-term debt. See Note 21.

(f) The ineffective portion of the changes in fair value of cash flow hedges was $3 million during 2006 and less than $1 million during 2005 on a pretax basis. Of the unrealized gains and losses recorded in accumulated other comprehensive loss as of December 31, 2006, a net gain of $2 million is expected to be reclassified to net income in 2007.

19. Fair Value of Financial Instruments

The fair value of the financial instruments disclosed herein is not necessarily representative of the amount that could be realized or settled, nor does the fair value amount consider the tax consequences of realization or settlement. The following table summarizes financial instruments, excluding derivative financial instruments disclosed in Note 18, by individual balance sheet line item. Marathon's financial instruments at December 31, 2006 and 2005 were:

(In millions) December 31	2006 Fair Value	2006 Carrying Amount	2005 Fair Value	2005 Carrying Amount
Financial assets:				
Cash and cash equivalents	**$ 2,585**	**$ 2,585**	$ 2,617	$ 2,617
Receivables	**4,177**	**4,177**	3,514	3,514
Receivables from United States Steel	**522**	**530**	540	552
Investments and long-term receivables[(a)]	**461**	**348**	268	195
Total financial assets	**$ 7,745**	**$ 7,640**	$ 6,939	$ 6,878
Financial liabilities:				
Accounts payable	**$ 5,850**	**$ 5,850**	$ 5,435	$ 5,435
Consideration payable under Libya re-entry agreement			732	732
Payables to United States Steel	**20**	**20**	6	6
Accrued interest	**89**	**89**	96	96
Long-term debt due within one year[(b)]	**450**	**450**	302	302
Long-term debt[(b)]	**3,279**	**2,947**	4,052	3,573
Total financial liabilities	**$ 9,688**	**$ 9,356**	$ 10,623	$ 10,144

(a) Excludes equity method investments and derivatives.

(b) Excludes capital leases.

The fair value of financial instruments classified as current assets or liabilities approximates carrying value due to the short-term maturity of the instruments. The fair value of investments and long-term receivables was based on discounted cash flows or other specific instrument analysis. The fair value of long-term debt instruments was based on market prices where available or current borrowing rates available for financings with similar terms and maturities. The fair value of the receivables from United States Steel was estimated using market prices for United States Steel debt assuming the industrial revenue bonds are redeemed on or before the tenth anniversary of the Separation per the Financial Matters Agreement.

20. Short-Term Debt

Marathon has a commercial paper program that is supported by the unused and available credit on the Marathon five-year revolving credit facility discussed in Note 21. At December 31, 2006, there were no commercial paper borrowings outstanding.

Additionally, as part of the Acquisition on June 30, 2005 discussed in Note 6, Marathon assumed $1.920 billion in debt which was repaid on July 1, 2005.

21. Long-Term Debt

(In millions)

December 31	2006	2005
Marathon Oil Corporation:		
Revolving credit facility due 2011[a]	**$**	$
6.650% notes due 2006		300
5.375% notes due 2007[b]	**450**	450
6.850% notes due 2008	**400**	400
6.125% notes due 2012[b]	**450**	450
6.000% notes due 2012[b]	**400**	400
6.800% notes due 2032[b]	**550**	550
9.375% debentures due 2012[c]	**123**	163
9.125% debentures due 2013[c]	**212**	271
9.375% debentures due 2022[c]	**67**	81
8.500% debentures due 2023[c]	**122**	123
8.125% debentures due 2023[c]	**181**	229
6.570% promissory note due 2006[b]		2
Series A medium term notes due 2022	**3**	3
4.750% 6.875% obligations relating to industrial development and environmental improvement bonds and notes due 2009 2033[d]	**439**	453
Sale-leaseback financing due 2007 2012[e]	**60**	66
Capital lease obligation due 2007 2012[f]	**44**	49
Consolidated subsidiaries:		
Revolving credit facility due 2009[g]		
Capital lease obligations due 2007 2020	**59**	61
Total[h][i]	**3,560**	4,051
Unamortized discount	**(6)**	(8)
Fair value adjustments on notes subject to hedging[j]	**(22)**	(30)
Amounts due within one year	**(471)**	(315)
Long-term debt due after one year	**$ 3,061**	$ 3,698

(a) In May 2006, Marathon entered into an amendment of its $1.5 billion five-year revolving credit agreement, expanding the size of the facility to $2 billion and extending the termination date from May 2009 to May 2011. The facility requires a representation at an initial borrowing that there has been no change in Marathon's consolidated financial position or operations, considered as a whole, that would materially and adversely affect its ability to perform its obligations under the revolving credit facility. Interest on the facility is based on defined short-term market rates. During the term of the agreement, Marathon is obligated to pay a variable facility fee on the total commitment, which at December 31, 2006 was 0.08 percent. At December 31, 2006, there were no borrowings outstanding under this facility.

(b) These notes contain a make-whole provision allowing Marathon the right to repay the debt at a premium to market price.

(c) During 2006, Marathon extinguished portions of this debt. Debt with a total face value of $162 million was repurchased at a weighted average price equal to 122 percent of face value. The total premium of $35 million is reflected as loss on early extinguishment of debt in the consolidated statement of income for 2006.

(d) United States Steel has assumed responsibility for repayment of $415 million of these obligations. The Financial Matters Agreement provides that, on or before the tenth anniversary of the Separation, United States Steel will provide for Marathon's dischage from any remaining liability under any of the assumed industrial revenue bonds.

(e) This sale-leaseback financing arrangement relates to a lease of a slab caster at United States Steel's Fairfield Works facility in Alabama. Marathon is the primary obligor under this lease. Under the Financial Matters Agreement, United States Steel has assumed responsibility for all obligations under this lease. This lease is an amortizing financing with a final maturity of 2012, subject to additional extensions.

(f) This obligation relates to a lease of equipment at United States Steel's Clairton Works cokemaking facility in Pennsylvania. Marathon is the primary obligor under this lease. Under the Financial Matters Agreement, United States Steel has assumed responsibility for all obligations under this lease. This lease is an amortizing financing with a final maturity of 2012.

(g)

MPC's $500 million five-year revolving credit agreement was terminated concurrent with the May 2006 amendment of Marathon's revolving credit facility.

(h) Required payments of long-term debt for the years 2008-2011 are $417 million, $19 million, $21 million and $164 million. Of these amounts, payments assumed by United States Steel are $14 million, $15 million, $17 million and $161 million.

(i) In the event of a change in control of Marathon, as defined in the related agreements, debt obligations totaling $1.183 billion at December 31, 2006, may be declared immediately due and payable.

(j) See Note 18 for information on interest rate swaps.

In 2006, Marathon entered into a loan agreement which provides for borrowings of up to $525 million from the Norwegian export credit agency based upon the amount of qualifying purchases by Marathon of goods and services from Norwegian suppliers. The loan agreement allows Marathon to select either a fixed or LIBOR-based floating interest rate at the time of the initial drawdown and a five-year or eight and one half-year repayment term. If Marathon elects to borrow under this agreement, the initial drawdown must occur in June 2007 with one subsequent drawdown allowed in December 2007.

22. MPC Receivables Purchase and Sale Facility

On July 1, 2005, MPC entered into a $200 million, three-year Receivables Purchase and Sale Agreement with certain purchasers. The program was structured to allow MPC to periodically sell a participating interest in pools of eligible accounts receivable. During 2006, the facility was terminated. No receivables were sold under the agreement during its term.

23. Supplemental Cash Flow Information

(In millions)	2006	2005	2004
Net cash provided from operating activities from continuing operations included:			
Interest paid (net of amounts capitalized)	**$ 96**	$ 174	$ 206
Income taxes paid to taxing authorities	**4,149**	1,528	672
Income tax settlements paid to United States Steel	**35**	6	3
Commercial paper and revolving credit arrangements, net:			
Commercial paper issuances	**$ 1,321**	$ 3,896	$
repayments	**(1,321)**	(3,896)	
Credit agreements borrowings		10	
repayments		(10)	
Ashland credit agreements borrowings			653
repayments			(653)
Total	**$**	$	$
Noncash investing and financing activities:			
Asset retirement costs capitalized	**$ 286**	$ 171	$ 66
Debt payments assumed by United States Steel	**24**	44	13
Capital lease obligations:			
Assets acquired	**1**	18	
Net assets contributed to joint ventures		7	3
Acquisitions:			
Debt and other liabilities assumed	**26**	4,161	
Common stock issued to seller		955	
Receivables transferred to seller		911	
Disposal of assets:			
Asset retirement obligations assumed by buyer	**9**	6	

24. Defined Benefit and Other Postretirement Plans

Marathon has noncontributory defined benefit pension plans covering substantially all domestic employees as well as international employees located in Ireland, Norway and the United Kingdom. Benefits under these plans are based primarily on years of service and final average pensionable earnings. Marathon adopted SFAS No. 158, which applies to such plans, prospectively as of December 31, 2006.

Marathon also has defined benefit plans for other postretirement benefits covering most employees. Health care benefits are provided through comprehensive hospital, surgical and major medical benefit provisions subject to various cost sharing features. Life insurance benefits are provided to certain nonunion and union-represented retiree beneficiaries. Other postretirement benefits have not been funded in advance.

Obligations and funded status The following summarizes the obligations and funded status for Marathon's defined benefit pension and other postretirement plans:

(In millions)	Pension Benefits 2006 U.S.	Pension Benefits 2006 Int'l	Pension Benefits 2005 U.S.	Pension Benefits 2005 Int'l	Other Benefits 2006	Other Benefits 2005
Change in benefit obligations						
Benefit obligations at January 1	**$ 2,055**	**$ 338**	$ 1,750	$ 322	**$ 776**	$ 697
Service cost	**117**	**17**	109	11	**23**	20
Interest cost	**113**	**17**	104	16	**42**	38
Actuarial (gain) loss	**(207)**[(a)]	**15**	187[(b)]	(6)	**9**	40[(b)]
Plan amendment	**117**[(c)]					10
Mergers and acquisitions[(d)]			2			2
Benefits paid	**(118)**	**(6)**	(97)	(5)	**(29)** [(e)]	(31)
Benefit obligations at December 31	**$ 2,077**	**$ 381**	$ 2,055	$ 338	**$ 821**	$ 776
Change in plan assets						
Fair value of plan assets at January 1	**$ 1,025**	**$ 222**	$ 949	$ 185		
Actual return on plan assets	**175**	**56**	45	16		
Employer contributions	**606**	**29**	128	26		
Benefits paid from plan assets	**(118)**	**(6)**	(97)	(5)		
Fair value of plan assets at December 31	**$ 1,688**	**$ 301**	$ 1,025	$ 222		
Funded status of plans at December 31, 2006	**$ (389)**	**$ (80)**			**$ (821)**	
Amounts recognized in the consolidated balance sheet:						
Current liabilities	**$ (8)**	**$ (1)**			**$ (36)**	
Noncurrent liabilities	**(381)**	**(79)**			**(785)**	
Accrued benefit cost	**$ (389)**	**$ (80)**			**$ (821)**	
Pretax amounts recognized in accumulated other comprehensive income in 2006[(f)]:						
Net loss	**$ 338**	**$ 70**			**$ 184**	
Prior service cost (credit)	**132**				**(53)**	
Funded status of plans at December 31, 2005			$ (1,030)	$ (116)		$ (776)
Unrecognized prior service cost (credit)			23			(64)
Unrecognized net loss			651	106		184
Accrued benefit cost			$ (356)	$ (10)		$ (656)
Amounts recognized in the consolidated balance sheet at December 31, 2005:						
Accrued benefit liability			$ (520)	$ (91)		$ (656)
Intangible asset			16			
Accumulated other comprehensive income, excluding tax effects			148	81		
Accrued benefit cost			$ (356)	$ (10)		$ (656)

	Pension Benefits	Other Benefits

(a) Includes the impact of an increase in the discount rate to 5.80 percent from 5.50 percent and demographic assumption changes, which decreased the obligation by $112 million.

(b) Includes the impact of decreasing the retirement age assumption by two years and increasing the lump sum election rate assumption from 90 percent to 96 percent based on changing trends in Marathon's experience, which increased the obligation by $109 million.

(c) Includes the impact of plan design changes related to the 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.

(d) Includes the addition of certain employees of the maleic anhydride business acquired as part of the Acquisition.

(e) Benefits paid include the $3 million Medicare Subsidy received.

(f) Excludes amounts related to LOOP LLC, an equity method investee with defined benefit pension and postretirement plans for which a net loss of $6 million is reflected in accumulated other comprehensive income as a result of adopting SFAS No. 158 as of December 31, 2006, reflecting Marathon's 51 percent share.

The accumulated benefit obligation for all defined benefit pension plans was $1.912 billion and $1.748 billion at December 31, 2006 and 2005. Marathon's international subsidiaries do not sponsor any defined benefit postretirement plans other than pension plans.

The following summarizes all of Marathon's defined benefit pension plans that have accumulated benefit obligations in excess of plan assets.

	December 31			
	2006		2005	
(In millions)	U.S.	Int'l	U.S.	Int'l
Projected benefit obligations	**$ (92)**	**$ (354)**	$ (2,055)	$ (338)
Accumulated benefit obligations	**(62)**	**(331)**	(1,435)	(313)
Fair value of plan assets		**278**	1,025	222

On June 30, 2005, as a result of the Acquisition, MPC's defined benefit pension and other postretirement plan obligations were remeasured using current discount rates and plan assumptions. The discount rate was decreased to 5.25 percent from 5.75 percent. As part of the application of the purchase method of accounting, MPC recognized 38 percent of its unrecognized net transition gain, prior service costs and actuarial losses related to its defined benefit pension and other postretirement plans. As a result, obligations related to the defined benefit pension and other postretirement plans increased by $264 million and $28 million.

Components of net periodic benefit cost and other comprehensive income The following summarizes the net periodic benefit costs and the amounts recognized as other comprehensive income for Marathon's defined benefit pension and other postretirement plans.

	Pension Benefits						Other Benefits		
	2006		2005		2004		2006	2005	2004
(In millions)	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l			
Components of net periodic benefit cost:									
Service cost	**$ 117**	**$ 17**	$ 109	$ 11	$ 94	$ 9	**$ 23**	$ 20	$ 18
Interest cost	**113**	**17**	104	16	95	14	**42**	38	42
Expected return on plan assets	**(103)**	**(15)**	(83)	(12)	(84)	(10)			
Amortization net transition gain			(3)		(4)				
prior service cost (credit)	**8**		4		4		**(11)**	(12)	(14)
actuarial loss	**34**	**7**	47	8	39	7	**9**	7	11
Multi-employer and other plans	**2**		2		2		**3**	3	3
Settlement, curtailment and termination losses (gains)[(a)]					37				(9)
Net periodic benefit cost	**$ 171**	**$ 26**	$ 180	$ 23	$ 183	$ 20	**$ 66**	$ 56	$ 51

(a) Includes business transformation costs.

	Pension Benefits			
	2005		2004	
(In millions)	U.S.	Int'l	U.S.	Int'l
Increase (decrease) in minimum liability included in other comprehensive income, excluding tax effects and minority interest	$ 81	$ 10	$ (18)	$ (13)

The estimated net loss and prior service cost for the defined benefit pension plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2007 are $21 million and $13 million. The estimated net loss and prior service credit for the other defined benefit postretirement plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2007 are $11 million and $10 million.

Plan assumptions The following summarizes the assumptions used to determine the benefit obligations and net periodic benefit cost for Marathon's defined benefit pension and other postretirement plans.

	Pension Benefits			Other Benefits		
	2006	2005	2004	2006	2005	2004

	Pension Benefits						Other Benefits		
	U.S.	**Int'l**	**U.S.**	**Int'l**	**U.S.**	**Int'l**			
Weighted-average assumptions used to determine benefit obligation at December 31:									
Discount rate	**5.80%**	**5.20%**	5.50%	4.70%	5.75%	5.30%	**5.90%**	5.75%	5.75%
Rate of compensation increase	**4.50%**	**4.75%**	4.50%	4.55%	4.50%	4.60%	**4.50%**	4.50%	4.50%
Weighted average actuarial assumptions used to determine net periodic benefit cost for years ended December 31:									
Discount rate[a]	**5.70%**	**4.70%**	5.57%	5.30%	6.25%	5.40%	**5.75%**	5.57%	6.25%
Expected long-term return on plan assets	**8.50%**	**6.07%**	8.50%	6.87%	9.00%	6.87%			
Rate of compensation increase	**4.50%**	**4.55%**	4.50%	4.60%	4.50%	4.50%	**4.50%**	4.50%	4.50%

(a) On July 31, 2006, due to an interim remeasurement, the discount rate for the U.S. pension plans was increased to 6.00 percent from 5.50 percent. Also, on June 30, 2005 due to the Acquisition, the discount rate for the MPC pension plan was decreased to 5.25 percent from 5.75 percent.

Expected long-term return on plan assets

U.S. Plans Historical markets are studied and long-term historical relationships between equities and fixed income securities are preserved consistent with the widely accepted capital market principle that assets with higher volatility generate a greater return over the long term. Certain components of the asset mix are modeled with various assumptions regarding inflation, debt returns and stock yields. The assumptions are compared to those of peer companies and to historical returns for reasonableness and appropriateness.

International Plans The overall expected long-term return on plan assets is derived using the expected returns on the individual asset classes, weighted by holdings as of year end. The long-term rate of return on equity investments is assumed to be 2.5 percent greater than the yield on local government bonds. Expected returns on debt securities are estimated directly at market yields and on cash are estimated at the local currency base rate.

Assumed health care cost trend The following summarizes the assumed health care cost trend rates.

December 31	2006	2005	2004
Health care cost trend rate assumed for the following year			
Medical	**8.0%**	8.5%	9.0%
Prescription Drugs[(a)]	**11.0%**	8.5%	9.0%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)			
Medical	**5.0%**	5.0%	5.0%
Prescription Drugs[(a)]	**6.0%**	5.0%	5.0%
Year that the rate reaches the ultimate trend rate			
Medical	**2012**	2012	2012
Prescription Drugs[(a)]	**2016**	2012	2012

(a) Prior to 2006, the assumed cost trend rate and the year that it would reach the ultimate trend rate for prescription drugs were the same as those for other medical costs.

Assumed health care cost trend rates have a significant effect on the amounts reported for defined benefit retiree health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

(In millions)	1-Percentage-Point Increase	1-Percentage-Point Decrease
Effect on total of service and interest cost components	$ 11	$ (9)
Effect on other postretirement benefit obligations	114	(93)

Plan assets The following summarizes the defined benefit pension plans' weighted-average asset allocations by asset category.

	2006		2005	
	U.S.	Int'l	U.S.	Int'l
Equity securities	**79%**	**73%**	76%	74%
Debt securities	**19%**	**26%**	22%	24%
Real estate	**2%**		2%	
Other		**1%**		2%
Total	**100%**	**100%**	100%	100%

Plan investment policies and strategies

U.S. Plans The investment policy reflects the funded status of the plans and Marathon's future ability to make further contributions. Historical performance and future expectations suggest that common stocks will provide higher total investment returns than fixed-income securities over a long-term investment horizon. As a result, equity investments will likely continue to exceed 50 percent of the value of the fund. Accordingly, bond and other fixed-income investments will comprise the remainder of the fund. Short-term investments shall reflect the liquidity requirements for making pension payments. The plans' targeted asset allocation is comprised of 75 percent equity securities and 25 percent fixed-income and real estate-related securities. Management of the plans' assets is delegated to the United States Steel and Carnegie Pension Fund. The fund manager has limited discretion to move away from the target allocations based upon the manager's judgment as to current confidence or concern for the capital markets. Investments are diversified by industry and type, limited by grade and maturity. The policy prohibits investments in any securities in the steel industry and allows derivatives subject to strict guidelines, such that derivatives may only be written against equity securities in the portfolio. Investment performance and risk is measured and monitored on an ongoing basis through quarterly investment meetings and periodic asset and liability studies.

International Plans The objective of the investment policy is to achieve a long-term return which is consistent with assumptions made by the actuary in determining the funding requirements of the plans. The target asset allocation is approximately 75 percent equity securities and 25 percent debt securities. The day-to-day management of the plans' assets is delegated to several professional investment managers. The spread of assets by type and the investment managers' policies on investing in individual securities within each type provide adequate diversification of investments. The use of derivatives by the investment managers is permitted and plan specific, subject to strict guidelines. Investment performance and risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews and periodic asset and liability studies.

Cash flows

Plan Contributions Marathon expects to make contributions to the Company's funded pension plans of approximately $50 million in 2007. Cash contributions to be paid from the general assets of the Company for the unfunded pension and postretirement benefit plans are expected to be approximately $8 million and $41 million in 2007.

Estimated Future Benefit Payments The following gross benefit payments, which reflect expected future service, as appropriate, are expected to be paid in the years indicated:

(In millions)	**Pension Benefits**		**Other Benefits**[(a)]
	U.S.	**Int'l**	
2007	$ 151	$ 6	$ 41
2008	166	7	44
2009	182	8	48
2010	195	9	52
2011	208	11	56
2012 through 2016	1,235	75	329

(a) Expected Medicare reimbursements for 2007 through 2016 total $64 million.

Other Plan Contributions Marathon also contributes to several defined contribution plans for eligible employees. Contributions to these plans totaled $47 million in 2006, $39 million in 2005 and $35 million in 2004.

25. Asset Retirement Obligations

The following summarizes the changes in asset retirement obligations:

(In millions)	**2006**	**2005**
Asset retirement obligations as of January 1	**$ 711**	$ 477
Liabilities incurred	**29**	20
Liabilities settled	**(16)**	(9)
Accretion expense (included in depreciation, depletion and amortization)	**43**	29
Adoption of FIN No. 47		53
Revisions of previous estimates	**277**	141
Asset retirement obligations as of December 31	**$ 1,044**	$ 711

26. Stock-Based Compensation Plans

Description of the plans The Marathon Oil Corporation 2003 Incentive Compensation Plan (the "Plan") authorizes the Compensation Committee of the Board of Directors to grant stock options, stock appreciation rights, stock awards, cash awards and performance awards to employees. The Plan also allows Marathon to provide equity compensation to its non-employee directors. No more than 20,000,000 shares of common stock may be issued under the Plan, and no more than 8,500,000 of those shares may be used for awards other than stock options or stock appreciation rights. Shares subject to awards that are forfeited, terminated, settled in cash, exchanged for other awards, tendered to satisfy the purchase price of an award or withheld to satisfy tax obligations or that expire unexercised or otherwise lapse become available for future grants. Shares issued as a result of awards granted under the Plan are generally funded out of common stock held in treasury, except to the extent there are insufficient treasury shares, in which case new common shares are issued.

The Plan replaced the 1990 Stock Plan, the Non-Officer Restricted Stock Plan, the Non-Employee Director Stock Plan, the deferred stock benefit provision of the Deferred Compensation Plan for Non-Employee Directors, the Senior Executive Officer Annual Incentive Compensation Plan and the Annual Incentive Compensation Plan (the "Prior Plans"). No new grants will be made from the Prior Plans. Any awards previously granted under the Prior Plans shall continue to vest and/or be exercisable in accordance with their original terms and conditions.

Stock-based awards under the Plan

Stock options Marathon grants stock options under the Plan. Marathon's stock options represent the right to purchase shares of common stock at the fair market value of the common stock on the date of grant. Through 2004, certain options were granted with a tandem stock appreciation right, which allows the recipient to instead elect to receive cash and/or common stock equal to the excess of the fair market value of shares of common stock, as determined in accordance with the Plan, over the option price of the shares. Most stock options granted under the Plan vest ratably over a three-year period and have a maximum term of ten years from the date they are granted.

Stock appreciation rights Prior to 2005, Marathon granted SARs under the Plan. Similar to stock options, stock appreciation rights represent the right to receive a payment equal to the excess of the fair market value of shares of common stock on the date the right is exercised over the grant price. Certain SARs were granted as stock-settled SARs and others were granted in tandem with stock options. In general, SARs that have been granted under the Plan vest ratably over a three-year period and have a maximum term of ten years from the date they are granted.

Stock-based performance awards In 2003 and 2004, the Compensation Committee granted stock-based performance awards to certain officers of Marathon and its consolidated subsidiaries under the Plan. Beginning in 2005, Marathon discontinued granting stock-based performance awards and instead grants cash-settled performance units to officers. The stock-based performance awards represent shares of common stock that are subject to forfeiture provisions and restrictions on transfer. Those restrictions may be removed if certain pre-established performance measures are met. The stock-based performance awards granted under the Plan will vest at the end of a 36-month performance period to the extent that the performance targets are achieved and the recipient is employed by Marathon on that date. Additional shares could be granted at the end of this performance period should performance exceed the targets. Prior to vesting, the recipients have the right to vote and receive dividends on the target number of shares awarded. However, the shares are not transferable until after they vest.

Restricted stock Marathon grants restricted stock and restricted stock units under the Plan. In 2005, the Compensation Committee began granting time-based restricted stock to officers as part of their annual long-term incentive package. The restricted stock awards to officers vest three years from the date of grant, contingent on the recipient's continued employment. Marathon also grants restricted stock to certain non-officer employees and restricted stock units to certain international non-officer employees (together with the restricted stock granted to officers above, "restricted stock awards") based on their performance within certain guidelines and for retention purposes. The restricted stock awards to non-officers generally vest in one-third increments over a three-year period, contingent on the recipient's continued employment. Prior to vesting, all restricted stock recipients have the right to vote such stock and receive dividends thereon. The non-vested shares are not transferable and are held by the Company's transfer agent.

Common stock units Marathon maintains an equity compensation program for its non-employee directors under the Plan. All non-employee directors other than the Chairman receive annual grants of common stock units under the Plan and they are required to hold those units until they leave the Board of Directors. When dividends are paid on Marathon common stock, directors receive dividend equivalents in the form of additional common stock units. Prior to January 1, 2006, non-employee directors had the opportunity to receive a matching grant of up to 1,000 shares of common stock if they purchased an equivalent number of shares within 60 days of joining the Board.

Stock-based compensation expense Total employee stock-based compensation expense was $83 million, $111 million and $61 million in 2006, 2005 and 2004. The total related income tax benefits were $31 million, $39 million and $22 million. In 2006, cash received upon exercise of stock option awards was $50 million. Tax benefits realized for deductions during 2006 that were in excess of the stock-based compensation expense recorded for options exercised and other stock-based awards vested during the period totaled $36 million. Cash settlements of stock option awards totaled $3 million in 2006.

Stock option awards granted During 2006, 2005 and 2004, Marathon granted stock option awards to both officer and non-officer employees. The weighted average grant date fair values of these awards were based on the following Black-Scholes assumptions:

	2006	**2005**	**2004**
Weighted average exercise price per share	**$ 75.68**	$ 50.28	$ 33.61
Expected annual dividends per share	**$ 1.60**	$ 1.32	$ 1.00
Expected life in years	**5.1**	5.5	5.5
Expected volatility	**28%**	28%	32%
Risk-free interest rate	**5.0%**	3.8%	3.9%
Weighted average grant date fair value of stock option awards granted	**$ 20.37**	$ 12.30	$ 8.83

Outstanding stock-based awards The following is a summary of stock option award activity.

	Number of Shares	Weighted-Average Exercise Price
Outstanding at December 31, 2003	9,006,380	$ 28.33
Granted	2,067,300	33.28
Exercised	(2,963,546)	17.17
Canceled	(96,886)	30.78
Outstanding at December 31, 2004	8,013,248	29.84
Granted	1,894,720	50.28
Exercised	(3,786,828)	29.37
Canceled	(113,186)	33.96
Outstanding at December 31, 2005	6,007,954	36.51
Granted	1,601,800	75.68
Exercised	(2,018,629)	23.22
Canceled	(95,630)	51.42
Outstanding at December 31, 2006[a]	5,495,495	49.43

(a) Of the stock option awards outstanding as of December 31, 2006, 5,076,185 and 419,310 were outstanding under the 2003 Incentive Compensation Plan and 1990 Stock Plan, including 489,691 stock options with tandem SARs.

The intrinsic value of stock option awards exercised during 2006, 2005 and 2004 was $107 million, $90 million and $27 million. Of those amounts, $32 million, $61 million and $19 million relate to stock options with tandem SARs.

The following table presents information on stock option awards at December 31, 2006:

	Outstanding			Exercisable	
Range of Exercise Prices	Number of Shares Under Option	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number of Shares Under Option	Weighted-Average Exercise Price
$ 25.50 26.91	556,450	6	$ 25.53	556,450	$ 25.53
$ 28.12 30.88	189,685	5	28.39	189,685	28.39
$ 32.52 34.00	1,596,430	7	33.51	949,555	33.44
$ 47.65 51.67	1,568,630	8	50.13	379,244	49.75
$ 75.64 81.02	1,584,300	9	75.68		
Total	5,495,495	8	49.43	2,074,934	33.84

As of December 31, 2006, the aggregate intrinsic value of stock option awards outstanding was $237 million. The aggregate intrinsic value and weighted average remaining contractual life of stock option awards currently exercisable were $122 million and 7 years. As of December 31, 2006, the number of fully-vested stock option awards and stock option awards expected to vest was 5,061,806. The weighted average exercise price and weighted average remaining contractual life of these stock option awards were $48.52 and 8 years and the aggregate intrinsic value was $223 million. As of December 31, 2006, unrecognized compensation cost related to stock option awards was $32 million, which is expected to be recognized over a weighted average period of 2 years.

The following is a summary of stock-based performance award and restricted stock award activity.

	Stock-Based Performance Awards	Weighted Average Grant Date Fair Value	Restricted Stock Awards	Weighted Average Grant Date Fair Value
Unvested at December 31, 2005	448,600	$ 29.93	985,556	$ 47.94
Granted	67,848[a]	76.82	218,980	80.90
Vested	(273,448)	38.30	(388,597)	41.18
Forfeited	(6,000)	33.61	(39,790)	53.10
Unvested at December 31, 2006	237,000	33.61	776,149	60.42

(a) Additional shares were issued in 2006 because the performance targets were exceeded for the 36-month performance period related to the 2003 grant.

During 2006, 2005 and 2004 the weighted average grant date fair value of restricted stock awards was $80.90, $54.41 and $36.55. During 2004, the weighted average grant date fair value of stock-based performance awards was $33.61. The vesting date fair value of stock-based performance awards which vested during 2006, 2005 and 2004 was $21 million, $5 million and $4 million. The vesting date fair value of restricted stock awards which vested during 2006, 2005 and 2004 was $32 million, $13 million and $7 million.

As of December 31, 2006, there was $29 million of unrecognized compensation cost related to stock-based performance awards and restricted stock awards which is expected to be recognized over a weighted average period of two years.

27. Stock Repurchase Program

On January 29, 2006, Marathon's Board of Directors authorized the repurchase of up to $2 billion of common stock. As of December 31, 2006, the Company had acquired 20.7 million common shares at a cost of $1.698 billion. On January 28, 2007, Marathon's Board of Directors authorized an extension of the share repurchase program by an additional $500 million. Purchases under the program may be in either open market transactions, including block purchases, or in privately negotiated transactions. The Company will use cash on hand, cash generated from operations or cash from available borrowings to acquire shares. This program may be changed based upon our financial condition or changes in market conditions and is subject to termination prior to completion.

28. Leases

Marathon leases a wide variety of facilities and equipment under operating leases, including land and building space, office equipment, production facilities and transportation equipment. Most long-term leases include renewal options and, in certain leases, purchase options. Future minimum commitments for capital lease obligations (including sale-leasebacks accounted for as financings) and for operating lease obligations having remaining noncancelable lease terms in excess of one year are as follows:

(In millions)	Capital Lease Obligations	Operating Lease Obligations
2007	$ 36	$ 159
2008	27	160
2009	27	136
2010	28	101
2011	27	68
Later years	71	259
Sublease rentals		(32)
Total minimum lease payments	216	$ 851
Less imputed interest costs	53	
Present value of net minimum lease payments included in long-term debt	$ 163	

In connection with past sales of various plants and operations, Marathon assigned and the purchasers assumed certain leases of major equipment used in the divested plants and operations of United States Steel. In the event of a default by any of the purchasers, United States Steel has assumed these obligations; however, Marathon remains primarily obligated for payments under these leases. Minimum lease payments under these operating lease obligations of $31 million have been included above and an equal amount has been reported as sublease rentals.

Of the $163 million present value of net minimum capital lease payments, $104 million was related to obligations assumed by United States Steel under the Financial Matters Agreement. Of the $851 million total minimum operating lease payments, $3 million was assumed by United States Steel under the Financial Matters Agreement.

Operating lease rental expense was:

(In millions)	**2006**	**2005**	**2004**
Minimum rental	**$ 197**[(a)]	$ 165[(a)]	$ 168[(a)]
Contingent rental	**28**	21	15
Sublease rentals	**(7)**	(14)	(12)
Net rental expense	**$ 218**	$ 172	$ 171

(a) Excludes $9 million, $10 million and $11 million paid by United States Steel in 2006, 2005 and 2004 on assumed leases.

29. Sale of Minority Interests in EGHoldings

In connection with the formation of Equatorial Guinea LNG Holdings Limited, GEPetrol was given certain contractual rights that gave GEPetrol the option to purchase and resell a 13 percent interest in EGHoldings held by Marathon to a third party. On July 25, 2005, GEPetrol exercised these rights and reimbursed Marathon for its actual costs incurred up to the date of closing, plus an additional specified rate of return. Marathon and GEPetrol entered into agreements under which Mitsui and a subsidiary of Marubeni acquired 8.5 percent and 6.5 percent interests in EGHoldings. As part of these agreements, Marathon sold a 2 percent interest in EGHoldings to Mitsui for its actual costs incurred up to the date of closing, plus a specified rate of return, as well as a premium and future consideration based upon the performance of EGHoldings. Following the transaction, Marathon held a 60 percent interest in EGHoldings, GEPetrol held a 25 percent interest and Mitsui and Marubeni held the remaining interests.

During 2005, Marathon received net proceeds of $163 million in connection with the transactions and recorded a gain, which is included in other income.

30. Contingencies and Commitments

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

Environmental matters Marathon is subject to federal, state, local and foreign laws and regulations relating to the environment. These laws generally provide for control of pollutants released into the environment and require responsible parties to undertake remediation of hazardous waste disposal sites. Penalties may be imposed for noncompliance. At December 31, 2006 and 2005, accrued liabilities for remediation totaled $101 million and $103 million. It is not presently possible to estimate the ultimate amount of all remediation costs that might be incurred or the penalties that may be imposed. Receivables for recoverable costs from certain states, under programs to assist companies in cleanup efforts related to underground storage tanks at retail marketing outlets, were $66 million and $68 million at December 31, 2006 and 2005.

On May 11, 2001, MPC entered into a consent decree with the U.S. Environmental Protection Agency which commits it to complete certain agreed upon environmental projects over an eight-year period primarily aimed at reducing air emissions at its seven refineries. The court approved this consent decree on August 28, 2001. The total one-time expenditures for these environmental projects are estimated to be approximately $425 million over the eight-year period, with about $365 million incurred through December 31, 2006. In addition, MPC 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.

Guarantees Marathon has issued the following guarantees:

(In millions)	Term	Maximum Potential Undiscounted Payments as of December 31, 2006
Indebtedness of equity method investees:		
LOOP[(a)]	Through 2024	$ 160
LOCAP[(a)]	Perpetual-Loan Balance Varies	23
Centennial[(b)]	Through 2024	75
Guarantees/indemnifications related to asset sales:		
Russia[(c)]	Indefinite	843
Yates[(d)]	Indefinite	228
Canada[(e)]	Indefinite	568
Miscellaneous asset sales[(f)]	Indefinite	68
Other:		
United States Steel[(g)]	Through 2012	680
Centennial Pipeline catastrophic event[(h)]	Indefinite	50
Alliance Pipeline[(i)]	Through 2015	59
Kenai Kachemak Pipeline LLC[(j)]	Through 2017	15
Corporate assets[(k)]	(k)	29

(a) Marathon holds interests in an offshore oil port, LOOP LLC ("LOOP"), and a crude oil pipeline system, LOCAP LLC ("LOCAP"). Both LOOP and LOCAP have secured various project financings with throughput and deficiency agreements. Under the agreements, Marathon is required to advance funds if the investees are unable to service debt. Any such advances are considered prepayments of future transportation charges. The terms of the agreements vary but tend to follow the terms of the underlying debt. Included in the underlying debt are a LOOP revolving credit facility of $25 million and a LOCAP revolving credit facility of $23 million.

(b) Marathon holds an interest in a refined products pipeline, Centennial Pipeline LLC ("Centennial"), and has guaranteed the repayment of Centennial's outstanding balance under a Master Shelf Agreement, which expires in 2024, and a Credit Agreement, which expires in 2007. The guarantees arose in order to obtain adequate financing. Prior to expiration of the Master Shelf Agreement, Marathon could be relinquished from responsibility under the guarantee should Centennial meet certain financial tests.

(c) In conjunction with the sale of its Russian businesses as discussed in Note 7, Marathon guaranteed the purchaser with regard to unknown obligations and inaccuracies in representations, warranties, covenants and agreements by Marathon. These indemnifications are part of the normal course of selling assets. Under the agreement, the maximum potential amount of future payments associated with these guarantees is equivalent to the proceeds from the sale.

(d) In 2003, Marathon sold its interest in the Yates field and gathering system. In accordance with this transaction, Marathon indemnified the purchaser from inaccuracies in Marathon's representations, warranties, covenants and agreements.

(e) In conjunction with the sale of certain Canadian assets during 2003, Marathon guaranteed the purchaser with regards to unknown environmental obligations and inaccuracies in Marathon's representations, warranties, covenants and agreements.

(f) Marathon entered into certain performance and general guarantees and environmental and general indemnifications in connection with certain asset sales.

(g) 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. In addition to the commitment to fund operating cash shortfalls of the partnership discussed in Note 3, United States Steel, under certain circumstances, is required to indemnify the limited partners if the partnership's product sales fail to qualify for the credit under Section 29 of the Internal Revenue Code. United States Steel has estimated the maximum potential amount of this indemnity obligation, including interest and tax gross-up, was approximately $680 million. Furthermore, United States Steel under certain circumstances has indemnified the partnership for environmental obligations.

(h) The agreement between Centennial and its members allows each member to contribute cash in lieu of Centennial procuring separate insurance in the event of third-party liability arising from a catastrophic event. Each member is to contribute cash in proportion to its ownership interest.

(i) Marathon is a party to a long-term transportation services agreement with Alliance Pipeline L.P. ("Alliance"). The agreement requires Marathon to pay minimum annual charges of approximately $7 million through 2015. The payments are required even if the transportation facility is not utilized. This contract has been used by Alliance to secure its financing. As a result of the Canadian asset sale discussed above, Husky has indemnified Marathon for any claims related to these guarantees.

(j) Marathon is an equity investor in Kenai Kachemak Pipeline LLC ("KKPL"), holding a 60 percent, noncontrolling interest. In April 2003, Marathon guaranteed KKPL's performance to properly construct, operate, maintain and abandon the pipeline in accordance with the Alaska Pipeline Act and the Right of Way Lease Agreement with the State of Alaska. The major obligations covered under the guarantee include maintaining the right-of-way, satisfying any liabilities caused by operation of the pipeline, and providing for the abandonment costs. Obligations that could arise under the guarantee would vary according to the circumstances triggering payment.

(k) Marathon has entered into leases of corporate assets containing general lease indemnities and guaranteed residual value clauses.

Contract commitments At December 31, 2006 and 2005, Marathon's contract commitments to acquire property, plant and equipment totaled $1.703 billion and $668 million. The $1.035 billion increase is primarily due to commitments related to the Garyville refinery expansion.

Agreements with joint owners As part of the formation of PTC, MPC and Pilot Corporation ("Pilot") entered into a Put/Call and Registration Rights Agreement (the "Agreement"). The Agreement provides that any time after

September 1, 2008, Pilot will have the right to sell its interest in PTC to MPC for an amount of cash and/or Marathon, MPC or Ashland equity securities equal to the product of 90 percent (95 percent if paid in securities) of the fair market value of PTC at the time multiplied by Pilot's percentage interest in PTC. At any time after September 1, 2011, under certain conditions, MPC will have the right to purchase Pilot's interest in PTC for an amount of cash and/or Marathon, MPC or Ashland equity securities equal to the product of 105 percent (110 percent if paid in securities) of the fair market value of PTC at the time multiplied by Pilot's percentage interest in PTC. Under the Agreement, MPC would determine the form of consideration to be paid upon exercise of the rights.

Other contingencies In November 2006, the government of Equatorial Guinea enacted a new hydrocarbon law governing petroleum operations in Equatorial Guinea. The transitional provision of the law provides that all contractors and the terms of any contract to which they are a party will be subject to the law. The governmental agency responsible for the energy industry was given the authority to renegotiate any contract for the purpose of adapting any terms and conditions that are inconsistent with the new law. Marathon is in the process of determining what impact this law may have on its existing operations in Equatorial Guinea.

31. Accounting Standards Not Yet Adopted

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 Marathon, SFAS No. 159 will be effective January 1, 2008, and retrospective application is not permitted. Should Marathon elect to apply the fair value option to any eligible items that exist at January 1, 2008, the effect of the first remeasurement to fair value would be reported as a cumulative effect adjustment to the opening balance of retained earnings. Marathon is currently evaluating the provisions of this statement.

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. For Marathon, SFAS No. 157 will be effective January 1, 2008, with early application permitted. Marathon is currently evaluating the provisions of this statement.

In September 2006, the 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 expenses such costs in the same annual period as incurred; however, estimated annual major maintenance costs are recognized as expense throughout the year on a pro rata basis. As such, adoption of FSP No. AUG AIR-1 will have no impact on Marathon's annual consolidated financial statements. Marathon is required to adopt the FSP effective January 1, 2007. Marathon does not believe the provisions of FSP No. AUG AIR-1 will have a significant impact on its interim consolidated financial statements.

In July 2006, the FASB issued 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. For Marathon, the provisions of FIN No. 48 are effective January 1, 2007. Marathon does not believe adoption of this statement will have a significant effect on its consolidated results of operations, financial position or cash flows.

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 is required to adopt SFAS No. 156 effective January 1, 2007. Marathon does not expect adoption of this statement to have a significant effect on its consolidated results of operations, financial position or cash flows.

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 provides 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. For Marathon, SFAS No. 155 is effective for all financial instruments acquired or issued on or after January 1, 2007. Marathon does not expect adoption of this statement to have a significant effect on its consolidated results of operations, financial position or cash flows.

Selected Quarterly Financial Data (Unaudited)

(In millions, except per share data)	2006				2005			
	4th Qtr.	**3rd Qtr.**	**2nd Qtr.**	**1st Qtr.**	**4th Qtr.**	**3rd Qtr.**	**2nd Qtr.**	**1st Qtr.**
Revenues	**$ 13,807**	**$ 16,492**	**$ 18,179**	**$ 16,418**	$ 17,088	$ 17,077	$ 15,942	$ 12,879
Income from operations	**1,793**	**2,944**	**2,754**	**1,476**	2,031	1,236	1,351	624
Income from continuing operations	**1,079**	**1,623**	**1,484**	**771**	1,265	750	668	323
Discontinued operations			**264**	**13**	19	20	5	1
Income before cumulative effect of change in accounting principle	**1,079**	**1,623**	**1,748**	**784**	1,284	770	673	324
Net income	**1,079**	**1,623**	**1,748**	**784**	1,265	770	673	324
Common stock data								
Net income per share:								
Basic	**$ 3.09**	**$ 4.55**	**$ 4.84**	**$ 2.15**	$ 3.46	$ 2.11	$ 1.94	$ 0.94
Diluted	**$ 3.06**	**$ 4.52**	**$ 4.80**	**$ 2.13**	$ 3.43	$ 2.09	$ 1.92	$ 0.93
Dividends paid per share	**$ 0.40**	**$ 0.40**	**$ 0.40**	**$ 0.33**	$ 0.33	$ 0.33	$ 0.28	$ 0.28
Price range of common stock[(a)]:								
Low	**$ 71.94**	**$ 70.73**	**$ 69.83**	**$ 65.24**	$ 56.28	$ 54.69	$ 44.00	$ 35.73
High	**$ 97.57**	**$ 92.19**	**$ 86.04**	**$ 78.15**	$ 69.21	$ 70.83	$ 55.58	$ 48.76

(a) Composite tape

Principal Unconsolidated Investees (Unaudited)

Company	Country	December 31, 2006 Ownership	Activity
Alba Plant LLC	Cayman Islands	52%[(a)]	Liquefied Petroleum Gas
Atlantic Methanol Production Company LLC	Cayman Islands	45%	Methanol Production
Centennial Pipeline LLC	United States	50%	Pipeline & Storage Facility
Kenai Kachemak Pipeline, LLC	United States	60%[(a)]	Natural Gas Transmission
Kenai LNG Corporation	United States	30%	Natural Gas Liquefaction
LOCAP LLC	United States	59%[(a)]	Pipeline & Storage Facilities
LOOP LLC	United States	51%[(a)]	Offshore Oil Port
Minnesota Pipe Line Company, LLC	United States	17%	Pipeline Facility
Muskegon Pipeline LLC	United States	60%[(a)]	Pipeline Facility
Odyssey Pipeline L.L.C.	United States	29%	Pipeline Facility
Pilot Travel Centers LLC	United States	50%	Travel Centers
Poseidon Oil Pipeline Company, L.L.C.	United States	28%	Crude Oil Transportation
Southcap Pipe Line Company	United States	22%	Crude Oil Transportation

(a) Represents a noncontrolling interest.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

The supplementary information is disclosed by the following geographic areas: the United States; Europe, which primarily includes activities in the United Kingdom, Ireland and Norway; Africa, which primarily includes activities in Angola, Equatorial Guinea, Gabon and Libya; and Other International, which includes activities in Canada, the Russian Federation and other international locations outside of Europe and Africa. Discontinued operations represent Marathon's Russian oil exploration and production businesses that were sold in 2006.

Capitalized Costs and Accumulated Depreciation, Depletion and Amortization[(a)]

(In millions) December 31	United States	Europe	Africa	Other Int'l	Total
2006 Capitalized costs:					
Proved properties	**$ 7,682**	**$ 7,216**	**$ 2,319**	**$ 1**	**$ 17,218**
Unproved properties	**938**	**77**	**206**	**4**	**1,225**
Suspended exploratory wells	**156**	**25**	**289**		**470**
Total	**8,776**	**7,318**	**2,814**	**5**	**18,913**
Accumulated depreciation, depletion and amortization:					
Proved properties	**5,141**	**4,771**	**412**	**1**	**10,325**
Unproved properties	**42**	**1**	**9**		**52**
Total	**5,183**	**4,772**	**421**	**1**	**10,377**
Net capitalized costs	**$ 3,593**	**$ 2,546**	**$ 2,393**	**$ 4**	**$ 8,536**
Share of equity method investees' capitalized costs	**$ 15**	**$**	**$ 361**	**$**	**$ 376**
2005 Capitalized costs:					
Proved properties	$ 7,015	$ 6,349	$ 1,857	$ 342	$ 15,563
Unproved properties	428	107	573	193	1,301
Suspended exploratory wells	111	31	204	17	363
Total	7,554	6,487	2,634	552	17,227
Accumulated depreciation, depletion and amortization:					
Proved properties	4,752	4,476	288	111	9,627
Unproved properties	27		9	32	68
Total	4,779	4,476	297	143	9,695
Net capitalized costs	$ 2,775	$ 2,011	$ 2,337	$ 409	$ 7,532
Share of equity method investees' capitalized costs	$ 13	$	$ 395	$	$ 408

(a) Includes capitalized asset retirement costs and the associated accumulated amortization.

Costs Incurred for Property Acquisition, Exploration and Development[(a)]

(In millions)	United States	Europe	Africa	Other Int'l	Continuing Operations	Discontinued Operations	Total

(In millions)	United States	Europe	Africa	Other Int'l	Continuing Operations	Discontinued Operations	Total
2006 Property acquisition:							
Proved	**$ 4**	**$**	**$ 19**	**$**	**$ 23**	**$**	**$ 23**
Unproved	**526**	**3**	**3**	**4**	**536**		**536**
Exploration	**224**	**36**	**169**	**70**	**499**	**2**	**501**
Development[(b)]	**603**	**607**	**40**		**1,250**	**43**	**1,293**
Capitalized asset retirement costs[(c)]	**78**	**201**	**13**	**2**	**294**	**1**	**295**
Total	**$ 1,435**	**$ 847**	**$ 244**	**$ 76**	**$ 2,602**	**$ 46**	**$ 2,648**
Share of investees' costs incurred	**$ 3**	**$**	**$ 1**	**$**	**$ 4**	**$**	**$ 4**
2005 Property acquisition:							
Proved	$ 3	$	$ 390	$	$ 393	$	$ 393
Unproved	31		381		412		412
Exploration	186	48	95	14	343	10	353
Development[(b)]	465	531	32		1,028	85	1,113
Capitalized asset retirement costs[(c)]	35	108	12	1	156	2	158
Total	$ 720	$ 687	$ 910	$ 15	$ 2,332	$ 97	$ 2,429
Share of investees' costs incurred			31		31		31
2004 Property acquisition:							
Proved	$ 9	$	$ 3	$	$ 12	$	$ 12
Unproved	10		1		11		11
Exploration	96	27	127	31	281	10	291
Development[(b)]	316	151	140		607	102	709
Capitalized asset retirement costs[(c)]	14	49	5		68	(5)	63
Total	$ 445	$ 227	$ 276	$ 31	$ 979	$ 107	$ 1,086
Share of investees' costs incurred	$ 1	$	$ 128	$	$ 129	$ 1	$ 130

(a) Includes costs incurred whether capitalized or expensed.

(b) Includes $12 million, $12 million and $8 million of costs incurred prior to assignment of proved reserves in 2006, 2005 and 2004. The associated reserves were awaiting full project sanction at the end of the applicable year.

(c) Includes the effect of foreign currency fluctuations.

Results of Operations for Oil and Gas Producing Activities

(In millions)	United States	Europe	Africa	Other Int'l	Total
2006 Revenues and other income:					
Sales[(a)]	**$ 2,329**	**$ 1,240**	**$ 1,300**	**$**	**$ 4,869**
Transfers	**307**	**58**	**1,168**		**1,533**
Other income[(b)]	**3**			**46**	**49**
Total revenues	**2,639**	**1,298**	**2,468**	**46**	**6,451**
Expenses:					
Production costs	**(512)**	**(207)**	**(126)**		**(845)**
Transportation costs[(c)]	**(124)**	**(44)**	**(33)**		**(202)**
Exploration expenses	**(169)**	**(29)**	**(91)**	**(73)**	**(362)**
Depreciation, depletion and amortization	**(458)**	**(281)**	**(127)**		**(866)**
Administrative expenses	**(41)**	**(10)**	**(6)**	**(36)**	**(92)**
Total expenses	**(1,304)**	**(571)**	**(383)**	**(109)**	**(2,367)**
Other production-related income[(d)]		**73**	**1**		**74**
Results before income taxes	**1,335**	**800**	**2,086**	**(63)**	**4,158**
Income tax provision (benefit)	**489**	**358**	**1,457**	**(4)**	**2,300**
Results of continuing operations	**$ 846**	**$ 442**	**$ 629**	**$ (59)**	**$ 1,858**
Results of discontinued operations	**$**	**$**	**$**	**$ 273**	**$ 273**
Share of equity method investees' results of operations	**$**	**$**	**$ 118**	**$**	**$ 118**
2005 Revenues and other income:					
Sales[(a)]	$ 2,227	$ 1,136	$ 71	$	$ 3,434
Transfers	422	38	810		1,270
Other income[(b)]	22				22
Total revenues	2,671	1,174	881		4,726
Expenses:					
Production costs	(448)	(170)	(82)	(3)	(703)
Transportation costs[(c)]	(114)	(40)	(27)		(181)
Exploration expenses	(118)	(31)	(27)	(38)	(214)
Depreciation, depletion and amortization	(411)	(255)	(87)		(753)
Administrative expenses	(34)	(8)	(5)	(25)	(72)
Total expenses	(1,125)	(504)	(228)	(66)	(1,923)
Other production-related income[(d)]	2	44			46
Results before income taxes	1,548	714	653	(66)	2,849
Income tax provision (benefit)	572	256	199	(13)	1,014
Results of continuing operations	$ 976	$ 458	$ 454	$ (53)	$ 1,835
Results of discontinued operations	$	$	$	$ 42	$ 42
Share of equity method investees' results of operations	$	$	$ 50	$	$ 50
2004 Revenues and other income:					
Sales[(a)]	$ 1,631	$ 876	$ 260	$	$ 2,767
Transfers	392	28	159		579
Total revenues	2,023	904	419		3,346
Expenses:					
Production costs	(381)	(166)	(55)	(5)	(607)
Transportation costs[(c)]	(112)	(35)	(6)		(153)
Exploration expenses	(79)	(19)	(28)	(32)	(158)

(In millions)	United States	Europe	Africa	Other Int'l	Total
Depreciation, depletion and amortization	(356)	(275)	(56)		(687)
Administrative expenses	(39)	(4)	(15)	(24)	(82)
Total expenses	(967)	(499)	(160)	(61)	(1,687)
Other production-related income[d]		15			15
Results before income taxes	1,056	420	259	(61)	1,674
Income tax provision (benefit)	374	154	96	(26)	598
Results of continuing operations	$ 682	$ 266	$ 163	$ (35)	$ 1,076
Results of discontinued operations	$	$	$	$ (47)	$ (47)
Share of equity method investees' results of operations included in continuing operations	$ 1	$	$ 9	$	$ 10
Share of equity method investees' results of operations included in discontinued operations	$	$	$	$ 1	$ 1

(a) Excludes noncash effects of changes in the fair value of certain long-term natural gas sales contracts in the United Kingdom.

(b) Includes net gains on asset dispositions.

(c) Includes the cost to prepare and move liquid hydrocarbons and natural gas to their points of sale.

(d) Includes revenues, net of associated costs, from activities that are an integral part of Marathon's production operations which may include processing and/or transportation of third-party production, the purchase and subsequent resale of natural gas utilized for reservoir management and providing storage capacity.

Results of Operations for Oil and Gas Producing Activities

The following reconciles results of continuing operations for oil and gas producing activities to E&P segment income:

(In millions)	2006	2005	2004
Results of continuing operations	**$ 1,858**	$ 1,835	$ 1,076
Items not included in results of continuing oil and gas operations, net of tax:			
Marketing income and technology costs	**40**	4	4
Income from equity method investments	**135**	52	11
Other	**1**	(4)	(1)
Items not allocated to E&P segment income:			
Gain on asset disposition	**(31)**		
E&P segment income	**$ 2,003**	$ 1,887	$ 1,090

Average Production Costs[a]

(per boe)	United States	Europe	Africa	Continuing Operations
2006	**$ 8.51**	**$ 8.36**	**$ 2.78**	**$ 6.48**
2005	7.11	6.45	3.33	6.18
2004	5.58	5.39	3.35	5.25

(a) Computed using production costs, excluding transportation costs, as disclosed in the Results of Operations for Oil and Gas Producing Activities and as defined by the Securities and Exchange Commission. Natural gas volumes were converted to barrels of oil equivalent using a conversion factor of six mcf of natural gas to one barrel of oil.

Average Realizations

	United States	Europe	Africa	Continuing Operations	Discontinued Operations
(excluding derivative gains and losses)					
2006 Liquid hydrocarbons (per bbl)	**$ 54.41**	**$ 64.02**	**$ 59.83**	**$ 58.63**	**$ 38.38**
Natural gas (per mcf)[a]	**5.76**	**6.78**	**0.27**	**5.52**	
2005 Liquid hydrocarbons (per bbl)	$ 45.41	$ 52.99	$ 46.27	$ 47.35	$ 33.47
Natural gas (per mcf)[a]	6.42	5.72	0.25	5.61	
2004: Liquid hydrocarbons (per bbl)	$ 32.76	$ 37.16	$ 35.11	$ 34.40	$ 22.65
Natural gas (per mcf)[a]	4.89	4.11	0.25	4.31	
(including derivative gains and losses)					
2006 Liquid hydrocarbons (per bbl)	**$ 54.41**	**$ 64.02**	**$ 59.83**	**$ 58.63**	**$ 38.38**
Natural gas (per mcf)[a]	**5.77**	**6.78**	**0.27**	**5.53**	

	United States	Europe	Africa	Continuing Operations	Discontinued Operations
2005 Liquid hydrocarbons (per bbl)	$ 45.41	$ 52.99	$ 46.27	$ 47.35	$ 33.47
Natural gas (per mcf)[(a)]	6.40	5.72	0.25	5.59	
2004 Liquid hydrocarbons (per bbl)	$ 29.11	$ 33.65	$ 35.11	$ 31.56	$ 22.62
Natural gas (per mcf)[(a)]	4.85	4.11	0.25	4.28	

(a) Excludes the resale of purchased natural gas utilized for reservoir management.

Estimated Quantities of Proved Oil and Gas Reserves

Estimates of the proved reserves have been prepared in-house teams of reservoir engineers and geoscience professionals. Reserve estimates are periodically reviewed by Marathon's Corporate Reserves Group to assure that rigorous professional standards and the reserves definitions prescribed by the U.S. Securities and Exchange Commission ("SEC") are consistently applied throughout the Company.

Proved reserves are the estimated quantities of oil 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.

Marathon's net proved reserve estimates have been adjusted as necessary to reflect all contractual agreements, royalty obligations and interests owned by others at the time of the estimate. Only reserves that are estimated to be recovered during the term of the current contract have been included in the proved reserve estimate unless there is a clear and consistent history of contract extension. Reserves from properties governed by production sharing contracts have been calculated using the "economic interest" method prescribed by the SEC. Reserves that are not currently considered proved, such as those that may result from extensions of currently proved areas or that may result from applying secondary or tertiary recovery processes not yet tested and determined to be economic are excluded. Purchased natural gas utilized in reservoir management and subsequently resold is also excluded. Marathon does not have any quantities of oil and gas reserves subject to long-term supply agreements with foreign governments or authorities in which Marathon acts as producer.

Proved developed reserves are the quantities of oil and gas expected to be recovered through existing wells with existing equipment and operating methods. In some cases, proved undeveloped reserves may require substantial new investments in additional wells and related facilities. Production volumes shown are sales volumes, net of any products consumed during production activities.

(Millions of barrels)	United States	Europe	Africa[a]	Continuing Operations	Discontinued Operations
Liquid Hydrocarbons					
Proved developed and undeveloped reserves:					
Beginning of year 2004	210	59	218	487	89
Purchase of reserves in place[b]	1		2	3	
Revisions of previous estimates	(1)	3	14	16	(51)
Improved recovery	1			1	
Extensions, discoveries and other additions	9	60	1	70	7
Production	(29)	(15)	(12)	(56)	(6)
End of year 2004	191	107	223	521	39
Purchase of reserves in place[b]			3	3	
Re-entry to Libya concessions			165	165	
Revisions of previous estimates	10	4	1	15	3
Improved recovery	2			2	
Extensions, discoveries and other additions	15			15	12
Production	(28)	(13)	(19)	(60)	(10)
Sales of reserves in place[b]	(1)			(1)	
End of year 2005	189	98	373	660	44
Purchase of reserves in place[b]			**1**	**1**	
Revisions of previous estimates	**2**	**8**	**49**	**59**	**1**
Improved recovery	**3**			**3**	
Extensions, discoveries and other additions	**6**	**15**	**15**	**36**	**4**
Production	**(28)**	**(13)**	**(41)**	**(82)**	**(4)**
Sales of reserves in place[b]					**(45)**
End of year **2006**	**172**	**108**	**397**	**677**	
Proved developed reserves:					
Beginning of year 2004	193	47	120	360	31

(Millions of barrels)	United States	Europe	Africa[(a)]	Continuing Operations	Discontinued Operations
End of year 2004	171	41	147	359	27
End of year 2005	165	39	368	572	31
End of year **2006**	**150**	**35**	**381**	**566**	

Estimated Quantities of Proved Oil and Gas Reserves (continued)

(Billions of cubic feet)	United States	Europe	Africa[a]	Continuing Operations	Discontinued Operations
Natural Gas					
Proved developed and undeveloped reserves:					
Beginning of year 2004	1,635	484	665	2,784	
Purchase of reserves in place[b]	1			1	
Revisions of previous estimates	(230)	7	916	693	
Extensions, discoveries and other additions	189	150	11	350	
Production[c]	(231)	(97)	(28)	(356)	
End of year 2004	1,364	544	1,564	3,472	
Purchase of reserves in place[b]			24	24	
Revisions of previous estimates	(78)	18	298	238	
Extensions, discoveries and other additions	135	3		138	
Production[c]	(211)	(79)	(34)	(324)	
Sales of reserves in place[b]	(1)			(1)	
End of year 2005	1,209	486	1,852	3,547	
Purchase of reserves in place[b]		**4**	**8**	**12**	
Revisions of previous estimates	**(5)**	**4**	**139**	**138**	
Extensions, discoveries and other additions	**59**	**20**	**24**	**103**	
Production[c]	**(194)**	**(70)**	**(26)**	**(290)**	
End of year **2006**	**1,069**	**444**	**1,997**	**3,510**	
Proved developed reserves:					
Beginning of year 2004	1,067	421	528	2,016	
End of year 2004	992	376	570	1,938	
End of year 2005	943	326	638	1,907	
End of year **2006**	**857**	**238**	**648**	**1,743**	

(a) Consists of estimated reserves from properties governed by production sharing contracts.

(b) The net positive or negative balance of proved reserves acquired or relinquished in property trades within the same geographic area is reported as purchases of reserves in place or sales of reserves in place, respectively.

(c) Excludes the resale of purchased gas utilized in reservoir management.

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Gas Reserves

Future cash inflows are computed by applying year-end prices of oil and natural gas relating to Marathon's proved reserves to the year-end quantities of those reserves. Future price changes are considered only to the extent provided by contractual arrangements in existence at year-end.

The assumptions used to compute the proved reserve valuation do not necessarily reflect Marathon's expectations of actual revenues to be derived from those reserves or their present worth. Assigning monetary values to the estimated quantities of reserves, described on the preceding page, does not reduce the subjective and ever-changing nature of such reserve estimates.

Additional subjectivity occurs when determining present values because the rate of producing the reserves must be estimated. In addition to uncertainties inherent in predicting the future, variations from the expected production rate also could result directly or indirectly from factors outside of Marathon's control, such as unintentional delays in development, environmental concerns, changes in prices or regulatory controls.

The reserve valuation assumes that all reserves will be disposed of by production. However, if reserves are sold in place or subjected to participation by foreign governments, additional economic considerations could also affect the amount of cash eventually realized.

Future production, transportation and administrative costs and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions.

Future income tax expenses are computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to Marathon's proved oil and gas reserves. Oil and gas related tax credits and allowances are recognized.

Discount was derived by using a discount rate of 10 percent annually.

(In millions) **December 31**	**United States**	**Europe**	**Africa**	**Total**
2006				
Future cash inflows	**$ 13,435**	**$ 8,713**	**$ 22,799**	**$ 44,947**
Future production, transportation and administrative costs	**(5,512)**	**(2,564)**	**(1,877)**	**(9,953)**
Future development costs	**(762)**	**(1,781)**	**(495)**	**(3,038)**
Future income tax expenses	**(2,217)**	**(1,709)**	**(14,847)**	**(18,773)**
Future net cash flows	**$ 4,944**	**$ 2,659**	**$ 5,580**	**$ 13,183**
10 percent annual discount for estimated timing of cash flows	**(1,818)**	**(408)**	**(2,439)**	**(4,665)**
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	**$ 3,126**	**$ 2,251**	**$ 3,141**	**$ 8,518**
2005				
Future cash inflows	$ 17,346	$ 10,007	$ 18,088	$ 45,441
Future production, transportation and administrative costs	(5,046)	(2,007)	(1,910)	(8,963)
Future development costs	(853)	(1,531)	(751)	(3,135)
Future income tax expenses	(3,738)	(3,199)	(9,687)	(16,624)
Future net cash flows	$ 7,709	$ 3,270	$ 5,740	$ 16,719
10 percent annual discount for estimated timing of cash flows	(2,862)	(829)	(2,427)	(6,118)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 4,847	$ 2,441	$ 3,313	$ 10,601
Standardized measure of discounted future net cash flows relating to discontinued operations				$ 216

(In millions) December 31	United States	Europe	Africa	Total
2004				
Future cash inflows	$ 12,377	$ 7,742	$ 5,709	$ 25,828
Future production, transportation and administrative costs	(4,337)	(1,950)	(951)	(7,238)
Future development costs	(585)	(1,801)	(294)	(2,680)
Future income tax expenses	(2,581)	(1,753)	(1,265)	(5,599)
Future net cash flows	$ 4,874	$ 2,238	$ 3,199	$ 10,311
10 percent annual discount for estimated timing of cash flows	(1,740)	(737)	(1,419)	(3,896)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves[(a)]	$ 3,134	$ 1,501	$ 1,780	$ 6,415
Standardized measure of discounted future net cash flows relating to discontinued operations				$ 54

Summary of Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

(In millions)

	2006	2005	2004
Sales and transfers of oil and gas produced, net of production, transportation and administrative costs	**$ (5,312)**	$ (3,754)	$ (2,689)
Net changes in prices and production, transportation and administrative costs related to future production	**(1,342)**	6,648	771
Extensions, discoveries and improved recovery, less related costs	**1,290**	700	1,349
Development costs incurred during the period	**1,251**	1,030	609
Changes in estimated future development costs	**(527)**	(552)	(628)
Revisions of previous quantity estimates	**1,319**	820	948
Net changes in purchases and sales of minerals in place	**30**	4,557	33
Accretion of discount	**1,882**	1,124	757
Net change in income taxes	**(660)**	(6,694)	(627)
Timing and other	**(14)**	307	97
Net change for the year	**(2,083)**	4,186	620
Beginning of year	**10,601**	6,415	5,795
End of year	**$ 8,518**	$ 10,601	$ 6,415
Net change for the year from discontinued operations	**$ (216)**	$ 162	$ (152)

Supplemental Statistics (Unaudited)

	2006	2005	2004
Net Liquid Hydrocarbon Sales (thousands of barrels per day)[(a)]			
United States	**76**	76	81
Europe	**35**	36	40
Africa	**112**	52	32
Total International	**147**	88	72
Worldwide Continuing Operations	**223**	164	153
Discontinued Operations	**12**	27	17
Worldwide	**235**	191	170
Natural gas liquids included in above	**23**	18	15
Net Natural Gas Sales (millions of cubic feet per day)[(a)(b)]			
United States	**532**	578	631
Europe	**243**	262	292
Africa	**72**	92	76
Total International	**315**	354	368
Worldwide	**847**	932	999
Total Worldwide Sales (thousands of barrels of oil equivalent per day)			
Continuing Operations	**365**	319	320
Discontinued Operations	**12**	27	17
Worldwide	**377**	346	337
Average Realizations[(c)]			
Liquid Hydrocarbons (dollars per barrel)			
United States	**$ 54.41**	$ 45.41	$ 32.76
Europe	**64.02**	52.99	37.16
Africa	**59.83**	46.27	35.11
Total International	**60.81**	49.04	36.24
Worldwide Continuing Operations	**58.63**	47.35	34.40
Discontinued Operations	**38.38**	33.47	22.65
Worldwide	**$ 57.58**	$ 45.42	$ 33.31
Natural Gas (dollars per thousand cubic feet)			
United States	**$ 5.76**	$ 6.42	$ 4.89
Europe	**6.74**	5.70	4.13
Africa	**0.27**	0.25	0.25
Total International	**5.27**	4.28	3.33
Worldwide	**$ 5.58**	$ 5.61	$ 4.31
Net Proved Reserves at year-end (developed and undeveloped)			
Liquid Hydrocarbons (millions of barrels)			
United States	**172**	189	191
International	**505**	515	369

	2006	2005	2004
Total	**677**	704	560
Developed reserves as a percentage of total net reserves	**84%**	86%	69%
Natural Gas (billions of cubic feet)			
United States	**1,069**	1,209	1,364
International	**2,441**	2,338	2,108
Total	**3,510**	3,547	3,472
Developed reserves as a percentage of total net reserves	**50%**	54%	56%

(a) Amounts represent net sales after royalties, except for Ireland where amounts are before royalties.

(b) Includes natural gas acquired for injection and subsequent resale of 46 mmcfd, 38 mmcfd and 19 mmcfd in 2006, 2005 and 2004. Effective July 1, 2005, the methodology for allocating sales volumes between natural gas produced from the Brae complex and third-party natural gas production was modified, resulting in an increase in volumes representing natural gas acquired for injection and subsequent resale.

(c) 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.

(Dollars in millions, except as noted)

	2006	2005	2004
Segment Income (Loss)			
Exploration and Production			
United States	**$ 873**	$ 983	$ 674
International	**1,130**	904	416
E&P segment	**2,003**	1,887	1,090
Refining, Marketing and Transportation[a]	**2,795**	1,628	568
Integrated Gas	**16**	55	37
Segment income	**4,814**	3,570	1,695
Items not allocated to segments, net of income taxes:			
Corporate and other unallocated items	**(212)**	(377)	(327)
Gain (loss) on long-term U.K. natural gas contracts	**232**	(223)	(57)
Discontinued operations	**277**	45	(33)
Gain on disposition of Syria interest	**31**		
Deferred income taxes tax legislation changes	**21**	15	
other adjustments[b]	**93**		
Loss on early extinguishment of debt	**(22)**		
Gain on sale of minority interests in EG Holdings		21	
Corporate insurance adjustment			(17)
Cumulative effect of change in accounting principle		(19)	
Net income	**$ 5,234**	$ 3,032	$ 1,261
Net income per common share basic (in dollars)	**$ 14.62**	$ 8.52	$ 3.75
diluted (in dollars)	**$ 14.50**	$ 8.44	$ 3.73
Capital expenditures			
Exploration and Production	**$ 2,169**	$ 1,366	$ 840
Refining, Marketing and Transportation[a]	**916**	841	794
Integrated Gas[c]	**307**	571	488
Discontinued Operations	**45**	94	106
Corporate	**41**	18	19
Total	**$ 3,478**	$ 2,890	$ 2,247
Exploration Expense			
United States	**$ 169**	$ 118	$ 78
International	**196**	99	80
Total	**$ 365**	$ 217	$ 158
Refinery Runs (thousands of barrels per day)			
Crude oil refined	**980**	973	939
Other charge and blend stocks	**234**	205	171
Total	**1,214**	1,178	1,110
Refined Product Yields (thousands of barrels per day)			
Gasoline	**661**	644	608
Distillates	**323**	318	299
Propane	**23**	21	22
Feedstocks and special products	**107**	96	94
Heavy fuel oil	**26**	28	25
Asphalt	**89**	85	77
Total	**1,229**	1,192	1,125
Refined Product Sales Volumes (thousands of barrels per day)[d][e]	**1,425**	1,455	1,400
Matching buy/sell volumes included in above(e)	**24**	77	71

(Dollars in millions, except as noted)

		2006		2005		2004
Refining and Wholesale Marketing Gross Margin ($ per gallon)[f]	**$**	**0.2288**	$	0.1582	$	0.0877
Speedway SuperAmerica						
Retail outlets at year-end		**1,636**		1,638		1,669
Gasoline & distillates sales (millions of gallons)		**3,301**		3,226		3,152
Gasoline & distillates gross margin (dollars per gallon)	**$**	**0.1156**	$	0.1230	$	0.1186
Merchandise sales	**$**	**2,706**	$	2,531	$	2,335
Merchandise gross margin	**$**	**667**	$	626	$	571

(a) RM&T segment income for 2005 and 2004 is net of $376 million and $539 million pretax minority interest in MPC. RM&T capital expenditures include MPC at 100 percent for all periods.

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

(c) Includes Equatorial Guinea LNG Holdings at 100 percent.

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

(e) As a result of the change in accounting for matching buy/sell arrangements on April 1, 2006, the reported sales volumes will be lower than the volumes determined under the previous accounting practices. See Note 2 to the consolidated financial statements.

(f) Sales revenue less cost of refinery inputs, purchased products and manufacturing expenses, including depreciation. As a result of the change in accounting for matching buy/sell transactions on April 1, 2006, the resulting per gallon statistic will be higher than the statistic that would have been calculated from amounts determined under previous accounting practices. See Note 2 to the consolidated financial statements.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13(a)-15(e) and 15(d)-15(e) under the Securities Exchange Act of 1934) was carried out under the supervision and with the participation of Marathon's management, including our Chief Executive Officer and Chief Financial Officer. As of the end of the period covered by this report based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective. During the period covered by this report, there were no changes in our internal controls over financial reporting that have materially affected, or were reasonably likely to materially affect, our internal controls over financial reporting.

Internal Controls

See "Management's Report on Internal Control over Financial Reporting" on page F-2.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information concerning the directors of Marathon required by this item is incorporated by reference to the material appearing under the heading "Election of Directors" in Marathon's Proxy Statement for the 2007 Annual Meeting of stockholders.

Marathon's Board of Directors has established the Audit Committee and determined our "Audit Committee Financial Expert." The information required to be disclosed is incorporated by reference to the material appearing under the sub-heading "Audit Committee" located under the heading "The Board of Directors and Governance Matters" in Marathon's Proxy Statement for the 2007 Annual Meeting of Stockholders.

Marathon has adopted a Code of Ethics for Senior Financial Officers. It is available on our website at www.marathon.com/Code_Ethics_Sr_Finan_Off/.

Executive Officers of the Registrant

The executive officers of Marathon or its subsidiaries and their ages as of February 1, 2007, are as follows:

Philip G. Behrman	56	Senior Vice President, Worldwide Exploration
Clarence P. Cazalot, Jr.	56	President and Chief Executive Officer, and Director
Janet F. Clark	52	Executive Vice President and Chief Financial Officer
Gary R. Heminger	53	Executive Vice President
Steven B. Hinchman	48	Senior Vice President, Worldwide Production
Jerry Howard	58	Senior Vice President, Corporate Affairs
Alard Kaplan	56	Vice President, Major Projects
Kenneth L. Matheny	59	Vice President, Investor Relations and Public Affairs
Paul C. Reinbolt	51	Vice President, Finance and Treasurer
David E. Roberts	46	Senior Vice President, Business Development
William F. Schwind, Jr.	62	Vice President, General Counsel and Secretary

Michael K. Stewart	49	Vice President, Accounting and Controller

With the exception of Ms. Clark, Mr. Kaplan 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.

Ms. Clark joined Marathon in January 2004 as senior vice president and chief financial officer. Prior to joining Marathon, she was employed by Nuevo Energy Company from 2001 to December 2003 as senior vice president and chief financial officer.

Mr. Kaplan joined Marathon in December 2003 as vice president, major projects. Prior to joining Marathon, he was employed by Foster Wheeler Corporation since 2001, with his most recent position as director of LNG for Foster Wheeler's Houston office.

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.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934, as amended, requires that the Company's directors and executive officers, and persons who own more than ten percent of a registered class of the Company's equity securities, file reports of beneficial ownership on Form 3 and changes in beneficial ownership on Form 4 or Form 5 with the Securities and Exchange Commission. Based solely on the Company's review of the reporting forms and written representations provided to the Company from the individuals required to file reports, the Company believes that each of its executive officers and directors has complied with the applicable reporting requirements for transactions in the Company's securities during the fiscal year ended December 31, 2006, except for Michael K. Stewart who filed one Form 4 report two days late relating to shares-for-tax withholding for a vesting of restricted stock granted to Mr. Stewart prior to his election as an executive officer of the Company.

Item 11. Executive Compensation

Information required by this item is incorporated by reference to the material appearing under the heading "Executive Compensation Tables and Other Information;" under the sub-headings "Compensation Committee" and "Compensation Committee Interlocks and Insider Participation" under the heading "The Board of Directors and Governance Matters;" and under the heading "Compensation Committee Report" in Marathon's Proxy Statement for the 2007 Annual Meeting of stockholders.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required by this item is incorporated by reference to the material appearing under the headings "Security Ownership of Certain Beneficial Owners" and "Security Ownership of Directors and Executive Officers" in Marathon's Proxy Statement for the 2007 Annual Meeting of stockholders.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information required by this item is incorporated by reference to the material appearing under the heading "Certain Relationships and Related Person Transactions," and under the sub-heading "Board and Committee Independence" under the heading "The Board of Directors and Governance Matters" in Marathon's Proxy Statement for the 2007 Annual Meeting of stockholders.

Item 14. Principal Accounting Fees and Services

Information required by this item is incorporated by reference to the material appearing under the heading "Information Regarding the Independent Registered Public Accounting Firm's Fees, Services and Independence" in Marathon's Proxy Statement for the 2007 Annual Meeting of stockholders.

PART IV

Item 15. Exhibits, Financial Statement Schedules

A. Documents Filed as Part of the Report

1. Financial Statements (see Part II, Item 8. of this report regarding financial statements)

2. Financial Statement Schedules

   Financial Statement Schedules listed under SEC rules but not included in this report are omitted because they are not applicable or the required information is contained in the financial statements or notes thereto.

3. Exhibits:

Any reference made to USX Corporation in the exhibit listing that follows is a reference to the former name of Marathon Oil Corporation, a Delaware corporation and the registrant, and is made because the exhibit being listed and incorporated by reference was originally filed before July, 2001, the date of the change in the registrant's name. References to Marathon Ashland Petroleum LLC or MAP are references to the entity now known as Marathon Petroleum Company LLC.

Exhibit No.	Description
2.	**Plan of Acquisition, Reorganization, Arrangement, Liquidation or Succession**
2.1*	Holding Company Reorganization Agreement, dated as of July 1, 2001, by and among USX Corporation, USX Holdco, Inc. and United States Steel LLC.
2.2*	Agreement and Plan of Reorganization, dated as of July 31, 2001, by and between USX Corporation and United States Steel LLC.
2.3++	Master Agreement, among Ashland Inc., ATB Holdings Inc., EXM LLC, New EXM Inc., Marathon Oil Corporation, Marathon Oil Company, Marathon Domestic LLC and Marathon Ashland Petroleum LLC, dated as of March 18, 2004 and Amendment No. 1 dated as of April 27, 2005 (incorporated by reference to Exhibit 2.1 on Amendment No. 3 to the Registration Statement on Form S-4/A (File No. 333-119694) of Marathon Oil Corporation filed on May 19, 2005).
2.4++	Amended and Restated Tax Matters Agreement among Ashland Inc., ATB Holdings Inc., EXM LLC, New EXM Inc., Marathon Oil Corporation, Marathon Oil Company, Marathon Domestic LLC and Marathon Ashland Petroleum LLC, dated as of April 27, 2005 (incorporated by reference to Exhibit 2.2 on Amendment No. 3 to the Registration Statement on Form S-4/A (File No. 333-119694) of Marathon Oil Corporation filed on May 19, 2005).
2.5++	Assignment and Assumption Agreement (VIOC Centers) between Ashland Inc. and ATB Holdings Inc., dated as of March 18, 2004 (incorporated by reference to Exhibit 2.3 to Marathon Oil Corporation's Amendment No. 1 to Form 8-K/A, filed on November 29, 2004).
2.6++	Assignment and Assumption Agreement (Maleic Business) between Ashland Inc. and ATB Holdings Inc., dated as of March 18, 2004 (incorporated by reference to Exhibit 2.4 to Marathon Oil Corporation's Amendment No. 1 to Form 8-K/A, filed on November 29, 2004).
3.	**Articles of Incorporation and Bylaws**
3.1*	Restated Certificate of Incorporation of Marathon Oil Corporation.

Exhibit No.	Description
3.2	By-laws of Marathon Oil Corporation (incorporated by reference to Exhibit 3.1 to Marathon Oil Corporation's Form 8-K filed on October 27, 2006).
4.	**Instruments Defining the Rights of Security Holders, Including Indentures**
4.1	Five Year Credit Agreement dated as of May 20, 2004 among Marathon Oil Corporation, the Co-Agents and other Lenders party thereto, Bank of America, N.A., as Syndication Agent, ABN Ambro Bank N.V., Citibank, N.A. and Morgan Stanley Bank, as Documentation Agents and JPMorgan Chase Bank, as Administrative Agent (incorporated by reference to Exhibit 4.1 to Marathon Oil Corporation's Form 10-Q for the quarter ended June 30, 2004).

4.2 Amendment No. 1 dated as of May 4, 2006 to Five-Year Credit Agreement dated as of May 20, 2004 among Marathon Oil Corporation, the Co-Agents and other Lenders party thereto, Bank of America, N.A., as Syndication Agent, Citibank, N.A. and Morgan Stanley Bank, as Documentation Agents and JPMorgan Chase Bank, as Administrative Agent (incorporated by reference to Exhibit 4.1 to Marathon Oil Corporation's Form 10-Q for the quarter ended March 31, 2006).

Pursuant to CFR 229.601(b)(4)(iii), instruments with respect to long-term debt issues have been omitted where the amount of securities authorized under such instruments does not exceed 10% of the total consolidated assets of Marathon. Marathon hereby agrees to furnish a copy of any such instrument to the Commission upon its request.

10. Material Contracts

10.1 Tax Sharing Agreement between USX Corporation and United States Steel LLC (converted into United States Steel Corporation) dated as of December 31, 2001 (incorporated by reference to Exhibit 99.3 to Marathon Oil Corporation's Form 8-K filed January 3, 2002).

10.2 Financial Matters Agreement between USX Corporation and United States Steel LLC (converted into United States Steel Corporation) dated as of December 31, 2001 (incorporated by reference to Exhibit 99.5 to Marathon Oil Corporation's Form 8-K, filed on January 3, 2002).

10.3 Insurance Assistance Agreement between USX Corporation and United States Steel LLC (converted into United States Steel Corporation) dated as of December 31, 2001 (incorporated by reference to Exhibit 99.6 to Marathon Oil Corporation's Form 8-K, filed on January 3, 2002).

10.4 Marathon Oil Corporation 2003 Incentive Compensation Plan, Effective January 1, 2003 (incorporated by reference to Appendix C to Marathon Oil Corporation's Definitive Proxy Statement on Schedule 14A filed on March 10, 2003).

10.5* Marathon Oil Corporation 1990 Stock Plan, as Amended and Restated Effective January 1, 2002.

10.6 Second Amended and Restated Marathon Oil Corporation Non-Officer Restricted Stock Plan, As Amended and Restated Effective January 2, 2002 (incorporated by reference to Exhibit 10.2 to Marathon Oil Corporation's Amendment No. 1 to Form 10-Q/A for the quarter ended September 30, 2002).

10.7 Marathon Oil Corporation Deferred Compensation Plan for Non-Employee Directors (Amended and Restated as of January 1, 2002) (incorporated by reference to Exhibit 10.12 to Marathon Oil Corporation's Amendment No. 1 to Form 10-Q for the quarter ended September 30, 2002).

10.8 First Amendment to the Marathon Oil Corporation Deferred Compensation Plan for Non-Employee Directors (Amended and Restated as of January 1, 2002) (incorporated by reference to Exhibit 10.1 to Marathon Oil Corporation's Form 8-K, filed on December 8, 2005).

10.9 Second Amendment to the Marathon Oil Corporation Deferred Compensation Plan for Non-Employee Directors (incorporated by reference to Exhibit 10.1 to Marathon Oil Corporation's form 8-K filed on October 27, 2006).

10.10 Form of Non-Qualified Stock Option Grant for Executive Officers granted under Marathon Oil Corporation's 1990 Stock Plan, as amended and restated effective January 1, 2002 (incorporated by reference to Exhibit 10.3 to Marathon Oil Corporation's Form 10-Q for the quarter ended September 30, 2004).

10.11 Form of Non-Qualified Stock Option Grant for MAP officers granted under Marathon Oil Corporation's 1990 Stock Plan, as amended and restated effective January 1, 2002 (incorporated by reference to Exhibit 10.14 to Marathon Oil Corporation's Annual Report on Form 10-K for the year ended December 31, 2005).

10.12 Form of Non-Qualified Stock Option with Tandem Stock Appreciation Right Award Agreement for Chief Executive Officer granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan, effective January 1, 2003 (incorporated by reference to Exhibit 10.4 to Marathon Oil

Corporation's Form 10-Q for the quarter ended September 30, 2004).

10.13 Form of Non-Qualified Stock Option with Tandem Stock Appreciation Right Award Agreement for Executive Committee members granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan, effective January 1, 2003 (incorporated by reference to Exhibit 10.5 to Marathon Oil Corporation's Form 10-Q for the quarter ended September 30, 2004).

10.14 Form of Non-Qualified Stock Option with Tandem Stock Appreciation Right Award Agreement for Officers granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan, effective January 1, 2003 (incorporated by reference to Exhibit 10.6 to Marathon Oil Corporation's Form 10-Q for the quarter ended September 30, 2004).

10.15 Form of Non-Qualified Stock Option Award Agreement for MAP officers granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan, effective January 1, 2003 (incorporated by reference to Exhibit 10.18 to Marathon Oil Corporation's Annual Report on Form 10-K for the year ended December 31, 2005).

10.16 Form of Stock Appreciation Right Award Agreement for Chief Executive Officer granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan, effective January 1, 2003 (incorporated by reference to Exhibit 10.7 to Marathon Oil Corporation's Form 10-Q for the quarter ended September 30, 2004).

10.17 Form of Stock Appreciation Right Award Agreement for Executive Committee members granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan, effective January 1, 2003 (incorporated by reference to Exhibit 10.8 to Marathon Oil Corporation's Form 10-Q for the quarter ended September 30, 2004).

10.18 Form of Stock Appreciation Right Award Agreement for Officers granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan, effective January 1, 2003 (incorporated by reference to Exhibit 10.9 to Marathon Oil Corporation's Form 10-Q for the quarter ended September 30, 2004).

10.19 Form of Non-Qualified Stock Option Award Agreement granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan (incorporated by reference to Exhibit 99.1 to Marathon Oil Corporation's Form 8-K, filed on May 27, 2005).

10.20 Form of Officer Restricted Stock Award Agreement granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan (incorporated by reference to Exhibit 99.2 to Marathon Oil Corporation's Form 8-K, filed on May 27, 2005).

10.21 Form of Performance Unit Award Agreement (2005-2007 Performance Cycle) granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan (incorporated by reference to Exhibit 99.3 to Marathon Oil Corporation's Form 8-K filed on May 27, 2005).

10.22 Marathon Oil Company Excess Benefit Plan (incorporated by reference to Exhibit 10.27 to Marathon Oil Corporation's Annual Report on Form 10-K for the year ended December 31, 2005).

10.23 First Amendment to Marathon Oil Company Excess Benefit Plan (incorporated by reference to Exhibit 10.1 to Marathon Oil Corporation's form 8-K filed on May 18, 2006).

10.24 Second Amendment to Marathon Oil Company Excess Benefit Plan (incorporated by reference to Exhibit 10.3 to Marathon Oil Corporation's form 8-K filed on October 10, 2006).

10.25 Marathon Oil Company Deferred Compensation Plan (incorporated by reference to Exhibit 10.28 to Marathon Oil Corporation's Annual Report on Form 10-K for the year ended December 31, 2005).

10.26 First Amendment to Marathon Oil Company Deferred Compensation Plan (incorporated by reference to Exhibit 10.1 to Marathon Oil Corporation's form 8-K filed on May 18, 2006).

10.27 Second Amendment to Marathon Oil Company Deferred Compensation Plan (incorporated by reference to Exhibit 10.4 to Marathon Oil Corporation's form 8-K filed on October 10, 2006).

10.28 Marathon Petroleum Company LLC Excess Benefit Plan (incorporated by reference to Exhibit 10.29 to Marathon Oil Corporation's Annual Report on Form 10-K for the year ended December 31, 2005).

10.29 First Amendment to Marathon Petroleum Company LLC Excess Benefit Plan (incorporated by reference to Exhibit 10.1 to Marathon Oil Corporation's form 8-K filed on October 10, 2006).

10.30 Marathon Petroleum Company LLC Deferred Compensation Plan (incorporated by reference to Exhibit 10.30 to Marathon Oil Corporation's Annual Report on Form 10-K for the year ended December 31, 2005).

10.31 First Amendment to Marathon Petroleum Company LLC Deferred Compensation Plan (incorporated by reference to Exhibit 10.2 to Marathon Oil Corporation's form 8-K filed on October 10, 2006).

10.32 Speedway SuperAmerica LLC Excess Benefit Plan (incorporated by reference to Exhibit 10.31 to Marathon Oil Corporation's Annual Report on Form 10-K for the year ended December 31, 2005).

10.33 Speedway SuperAmerica LLC Excess Benefit Plan Amendment (incorporated by reference to Exhibit 10.32 to Marathon Oil Corporation's Annual Report on Form 10-K for the year ended December 31, 2005).

10.34	Pilot JV Amendment to Deferred Compensation Plans and Excess Benefits Plans (incorporated by reference to Exhibit 10.33 to Marathon Oil Corporation's Annual Report on Form 10-K for the year ended December 31, 2005).
10.35	EMRO Marketing Company Deferred Compensation Plan (incorporated by reference to Exhibit 10.34 to Marathon Oil Corporation's Annual Report on Form 10-K for the year ended December 31, 2005).
10.36*	Form of Change of Control Agreement between Marathon Oil Corporation and Various Officers.
10.37	Letter Agreement between Marathon Oil Company and Janet F. Clark, executed December 9, 2003 (incorporated by reference to Exhibit 10(i) to Marathon Oil Corporation's Annual Report on Form 10-K for the year ended December 31, 2003).
12.1*	Computation of Ratio of Earnings to Combined Fixed Charges.
14.1	Code of Ethics for Senior Financial Officers (incorporated by reference to Exhibit 14. to Marathon Oil Corporation's Form 10-K for the year ended December 31, 2004).
21.1*	List of Significant Subsidiaries.
23.1*	Consent of Independent Registered Public Accounting Firm.
31.1*	Certification of President and Chief Executive Officer pursuant to Rule 13(a)-14 and 15(d)-14 under the Securities Exchange Act of 1934.
31.2*	Certification of Executive Vice President and Chief Financial Officer pursuant to Rule 13(a)-14 and 15(d)-14 under the Securities Exchange Act of 1934.
32.1*	Certification of President and Chief Executive Officer pursuant to 18 U.S.C. Section 1350.
32.2*	Certification of Executive Vice President and Chief Financial Officer pursuant to 18 U.S.C. Section 1350.

* Filed herewith

++ Marathon agrees to furnish supplementally a copy of any omitted schedule to the United States Securities and Exchange Commission upon request.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities and Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

March 1, 2007 MARATHON OIL CORPORATION

By: /s/ MICHAEL K. STEWART

Michael K. Stewart
Vice President, Accounting and Controller

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on March 1, 2007 on behalf of the registrant and in the capacities indicated.

Signature	Title
/s/ THOMAS J. USHER Thomas J. Usher	Chairman of the Board and Director
/s/ CLARENCE P. CAZALOT, JR. Clarence P. Cazalot, Jr.	President & Chief Executive Officer and Director
/s/ JANET F. CLARK Janet F. Clark	Executive Vice President and Chief Financial Officer
/s/ MICHAEL K. STEWART Michael K. Stewart	Vice President, Accounting and Controller
/s/ CHARLES F. BOLDEN, JR. Charles F. Bolden, Jr.	Director
/s/ DAVID A. DABERKO David A. Daberko	Director
/s/ WILLIAM L. DAVIS William L. Davis	Director
/s/ SHIRLEY ANN JACKSON Shirley Ann Jackson	Director
/s/ PHILIP LADER Philip Lader	Director
/s/ CHARLES R. LEE	Director

Signature	Title
Charles R. Lee	
/s/ DENNIS H. REILLEY	Director
Dennis H. Reilley	
/s/ SETH E. SCHOFIELD	Director
Seth E. Schofield	
/s/ JOHN W. SNOW	Director
John W. Snow	
/s/ DOUGLAS C. YEARLEY	Director
Douglas C. Yearley	