MARATHON OIL CORP
Form 10-K
March 06, 2006

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2005
Commission file number 1-5153
Marathon Oil Corporation
(Exact name of registrant as specified in its charter)

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

5555 San Felipe Road, Houston, TX 77056-2723
(Address of principal executive offices)
Tel. No. (713) 629-6600
Securities registered pursuant to Section 12 (b) of the Act:*

Title of Each Class

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. þ
Indicate by check mark whether the registrant is a large accelerated filer, an 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, 2005: $19.5 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 366,808,670 shares of Marathon Oil Corporation Common Stock outstanding as of January 31, 2006.

Documents Incorporated By Reference:

Portions of the registrant s proxy statement relating to its 2006 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, the Chicago Stock Exchange and the Pacific Stock Exchange.**

MARATHON OIL CORPORATION

Unless the context otherwise indicates, references in this Annual Report on Form 10-K to Marathon, we, our, or 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 5 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.

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Disclosures Regarding Forward-Looking Statements

This Annual Report on Form 10-K, particularly Item 1. Business, Item 1A. Risk Factors, Item 3. Legal Proceedings, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and Item 7A. Quantitative and Qualitative Disclosures about Market Risk, includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These statements typically contain words such as anticipate, believe, estimate, expect, forecast, plan, predict tar could, may, should, would or similar words, indicating that future outcomes are uncertain. In accordance with saf 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, 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, from 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 and produces 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 natural gas and products manufactured from natural gas, such as liquefied natural gas (LNG) and methanol on a worldwide basis. For operating segment and geographic financial information, see Note 8 to the consolidated financial statements.

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.)

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As of December 31, 2005 we were conducting exploration, development and production activities in nine countries. Principal exploration activities were in the United States, Norway, Angola, Equatorial Guinea, the United Kingdom and Canada. Principal development and production activities were in the United States, the United Kingdom, Ireland, Norway, Equatorial Guinea, Gabon and Russia.

On December 29, 2005, in conjunction with our partners in the former Oasis Group, we entered into an agreement with the National Oil Corporation of Libya on the terms under which the companies would return to their oil and natural gas exploration and production operations in the Waha concessions in Libya. See Note 5 to the consolidated financial statements.

Our 2005 worldwide net liquid hydrocarbon sales averaged 191,000 barrels per day (bpd), an increase of 12 percent from 2004 levels. Our 2005 worldwide net natural gas sales, including gas acquired for injection and subsequent resale, averaged 932 million cubic feet per day (mmcfd), a decrease of 7 percent compared to 2004. In total, our 2005 worldwide net sales averaged 346,000 barrels of oil equivalent (boe) per day, compared to 337,000 boe per day in 2004. (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 gas volume to obtain boe.) In 2006, our worldwide net production available for sale is expected to average approximately 365,000 to 395,000 boe per day, including 40,000 to 45,000 bpd from our Libya operations, excluding future acquisitions and dispositions.

The above projections of 2006 Libya and worldwide net liquid hydrocarbon and natural gas sales and production volumes are forward-looking statements. Some factors that could potentially affect timing and 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 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 thereto, 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 2005, we drilled 33 gross (21 net) exploratory wells of which 29 gross (18 net) wells encountered hydrocarbons. Of these 29 wells, one gross (zero net) well was temporarily suspended. Internationally, we drilled 13 gross (six net) exploratory wells of which 11 gross (five net) wells encountered hydrocarbons. Of these 11 gross (five net) wells, all were temporarily suspended or are in the process of completing.

United States The Gulf of Mexico continues to be a core area for us with the potential to add new reserves. At the end of 2005, we had interests in 129 blocks in the Gulf of Mexico, including 96 in the deepwater area.

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. Our plans are to develop this as a subsea tieback to area infrastructure. Commercial terms have been secured for the tieback and processing of Ozona production and we are attempting to secure a drilling 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 continued during 2005 and are progressing towards a possible re-entry and sidetrack before 2008. In 2005, a well drilled on a block directly offsetting the Flathead prospect encountered hydrocarbons. We hold a 100 percent operated interest in the Flathead prospect.

In 2005, we drilled a well on the Stones prospect located on Walker Ridge block 508 in the Gulf of Mexico to total depth and encountered hydrocarbons. Additional drilling is required to determine the commerciality of this prospect. We hold a 20 percent outside-operated interest in the Stones prospect.

Other United States exploration activity during 2005 included three gross (three net) wells in the Cook Inlet area of Alaska, all of which were discoveries, and 14 gross (six net) wells in the Anadarko Basin in Oklahoma, 13 gross (six net) of which were discoveries.

Norway We hold interests in over 1 million gross acres offshore Norway and plan to continue our exploration effort there. In late 2005, we began drilling an appraisal well at the outside-operated Gudrun discovery, which we expect will be completed in the first quarter of 2006 and followed by an evaluation of the well results.

Results for the Volund well (formerly Hamsun) are being analyzed and development scenarios are being examined including a possible tie-back to the Alvheim development. We own a 65 percent interest in Volund and serve as operator.

Angola Offshore Angola, we own a 10 percent interest in Block 31 and a 30 percent interest in Block 32. To date we have announced 13 discoveries on these blocks, which reinforces the potential of this trend. On Block 31, we have four previously announced discoveries which form a potential development area in the northeastern portion of the block (Plutao, Saturo, Marte and Venus). In 2005, we announced five additional discoveries located in the southeastern part of Block 31 (Palas, Ceres, Juno, Astraea and Hebe). On Block 32, we previously announced the Gindungo and Canela discoveries. In 2005, we announced the Gengibre discovery and also had a successful appraisal well on this discovery. Lastly, in early 2006, we announced another discovery on the Mostarda prospect. Continued exploration success reinforces the potential for a commercial development on Block 32.

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 approximately 11 miles southwest of the Alba Field. We are currently evaluating development scenarios for both the Deep Luba and Gardenia discoveries. These discoveries reinforce the potential of the Alba Block, in which we own a 63 percent interest.

In 2003, we announced a natural gas discovery on Block D offshore Equatorial Guinea, where we are the operator with a 90 percent interest. The discovery well is on the Bococo prospect, which is approximately six miles west of the Alba field. The well has been suspended for re-entry at a later date. Development scenarios for the Bococo gas discovery along with three earlier dry gas discoveries on Block D are being considered for further development.

Canada We are the operator and own a 30 percent interest in the Annapolis lease offshore Nova Scotia. In addition, we operate the adjacent Cortland lease where we own a 75 interest and the adjacent Empire lease where we own a 50 percent interest.

Production (including development activities)

United States Approximately 40 percent of our 2005 worldwide net liquid hydrocarbon sales and 62 percent of our worldwide net natural gas sales were produced from U.S. operations.

During 2005, our production in the Gulf of Mexico averaged 33,800 bpd of liquid hydrocarbons, representing 44 percent of our total U.S. net liquid hydrocarbon sales, and 84 mmcfd of natural gas, representing 14 percent of our total U.S. net natural gas sales. Net liquid hydrocarbon production in the Gulf of Mexico decreased by 1,900 bpd and net natural gas production decreased by 16 mmcfd from the prior year. The decrease in production is mainly due to natural field declines and the effects of five tropical storms or hurricanes during 2005. In September 2004, our Petronius platform suffered damage from Hurricane Ivan and was out of service until March 2005. At year-end 2005, we held interests in eight producing fields and seven platforms in the Gulf of Mexico, of which four platforms are operated by Marathon.

We are one of the largest natural gas producers in the Cook Inlet and adjacent Kenai Peninsula of Alaska. In 2005 our Alaskan net natural gas sales averaged 167 mmcfd, representing 29 percent of our total U.S. net natural gas sales. Our natural gas production from Alaska is seasonal in nature, trending down during the second and third quarters and increasing during the fourth and first quarters to meet local market winter demands. 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 32-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 2005 development program in the Cook Inlet included participation in the drilling of six wells.

Net liquid hydrocarbon sales from our Wyoming fields averaged 20,700 bpd in 2005 compared to 21,200 bpd in 2004. Net natural gas sales from our Wyoming fields averaged 104 mmcfd in 2005 compared to 108 mmcfd in 2004. The decrease in our Wyoming net natural gas sales is primarily attributed to lower production from the Powder River Basin, which averaged 66 mmcfd in 2005 compared to 69 mmcfd in 2004 primarily as a result of natural field decline, partially offset by development drilling. Development of the Powder River Basin continued in 2005 with approximately 195 wells drilled, compared to approximately 230 wells drilled in 2004. Water discharge regulations impacted the pace of development in the Powder River Basin in 2005. Additional development of our southwest

Wyoming interests continued in 2005 where we participated in the drilling of 35 wells.

Net natural gas sales from our Oklahoma fields averaged 77 mmcfd in 2005 compared to 82 mmcfd in 2004 primarily as a result of natural field decline, partially offset by development and exploratory drilling. Our 2005 development program continued to focus in the Anadarko Basin where we participated in the drilling of 82 wells.

Our share of liquid hydrocarbon sales from the Permian Basin region, which extends from southeast New Mexico to west Texas, averaged 15,900 bpd in 2005, compared to 18,900 bpd in 2004. Net natural gas sales from our New Mexico fields, primarily the Indian Basin field, averaged 59 mmcfd in 2005 compared to 85 mmcfd in 2004. These decreases in net sales are due to natural field declines.

Net natural gas sales from our Texas fields, primarily located in East Texas, averaged 73 mmcfd in 2005 compared to 65 mmcfd in 2004. This increase is primarily attributable to drilling in the Pearwood and Giddings fields. In addition, active development of the Mimms Creek field in East Texas continued in 2005.

During 2005, we announced the sanctioning of the Neptune deepwater development on Atwater Valley Blocks 573, 574, 575, 617 and 618 in the Gulf of Mexico. In 2004, we announced that the Neptune 7 appraisal well encountered hydrocarbons. This discovery followed the Neptune 3 discovery in 2002 and the Neptune 5 discovery in 2003. Two successful appraisal sidetrack wells were also drilled from the original Neptune 5 location. We hold a 30 percent interest in the Neptune unit which is located approximately 120 miles off the coast of Louisiana. The field will be developed with seven initial subsea wells tied back to a stand alone tension leg platform. Fabrication of the platform commenced in late 2005. The drilling and completion of the development wells is expected to begin during the first half of 2006. Neptune is expected to begin production in late 2007 or early 2008 reaching full production during 2008.

In 2003, we announced the Perseus discovery located on Viosca Knoll Block 830 in the Gulf of Mexico approximately five miles from the Petronius platform. Production from the initial development well at Perseus was expected to begin in 2004 but, due to hurricane activity in September 2004 and the resulting damage to the Petronius platform, production was delayed. The initial long-reach development well was drilled from the Petronius platform reaching a total depth of 30,855 feet, and first production commenced in April 2005. Drilling of a second long-reach development well began in September 2005 and is expected to reach the planned total depth of 31,598 feet in the first quarter of 2006. First production from this second well is anticipated in the second quarter of 2006. We own a 50 percent outside-operated interest in this block.

United Kingdom Our largest asset in the U.K. 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 Brae field and West Brae/Sedgwick 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 18,300 bpd of liquid hydrocarbons in 2005, compared with 15,900 bpd in 2004. The increase primarily resulted from the timing of sales of liquid hydrocarbons and improved performance from the West Brae reservoir. Our share of Brae natural gas sales averaged 169 mmcfd, which was lower than the 197 mmcfd in 2004 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 23 agreements with 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 Beryl group owns the remaining 50 percent. The SAGE pipeline transports gas from the Brae and Beryl areas and has a total wet natural gas capacity of approximately 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 0.8 bcf per day of third-party natural gas from the 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, each of which has a single well. Our share of sales from the Foinaven fields averaged 16,000 bpd of liquid hydrocarbons and 9 mmcfd of natural gas in 2005, compared to 21,900 bpd and 10 mmcfd in 2004, primarily as a result of the timing of sales of liquid hydrocarbons; however, reliability issues and natural field declines also contributed to the decrease.

Norway We are the operator and own a 65 percent interest in the Alvheim complex located on the Norwegian Continental Shelf. This development is comprised of the Kneler and Boa discoveries and the previously undeveloped Kameleon accumulation. During 2004, we received approval from the Norwegian authorities for our Alvheim plan of 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 signed a purchase and sale agreement in 2004 for the Odin multipurpose shuttle tanker, which will be modified to an FPSO. In 2004,

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the Alvheim partners reached agreement to tie-in the nearby Vilje discovery, in which we own a 47 percent interest, subject to the approval of the Norwegian government. In 2005, the Norwegian government approved the Vilje PDO. Our share of production from a combined Alvheim/Vilje development is expected to reach more than 50,000 boe per day with first production starting in early 2007.

During 2005, net liquid hydrocarbon and natural gas sales in Norway from the Heimdal, Vale, Byggve and Skirne fields averaged 2,000 bpd and 34 mmcfd. We own a 24 percent interest in the Heimdal field, a 47 percent interest in the Vale field and a 20 percent interest in the Skirne field, which came on stream during 2004.

Ireland We own a 100 percent interest in the Kinsale Head, Ballycotton and Southwest Kinsale fields in the Celtic Sea offshore Ireland. Net natural gas sales were 50 mmcfd in 2005, compared with 58 mmcfd in 2004. In February 2006, we acquired an 86.5 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.

We own an 18.5 percent interest in the outside-operated Corrib natural gas development project, located approximately 40 miles off Ireland s west coast. 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 in 2005 pending resolution of issues raised by opponents of the project. A government-commissioned independent safety review of the onshore pipeline associated with the proposed development has been completed and we are awaiting publication of the related report.

Equatorial Guinea We own a 63 percent interest in the Alba field offshore Equatorial Guinea and a 52 percent interest in an onshore liquefied petroleum gas processing plant held through an equity method investee. During 2005, net liquid hydrocarbon sales averaged 39,600 bpd and net natural gas sales averaged 92 mmcfd, compared to 18,900 bpd and 76 mmcfd in 2004. A condensate expansion project in Equatorial Guinea was completed during 2004 and ramped up to full production in early 2005. This expansion project increased condensate production from approximately 15,000 gross bpd to approximately 67,000 gross bpd (38,000 bpd net to Marathon). A liquefied petroleum gas (LPG) expansion project in Equatorial Guinea ramped up to full production in the third quarter of 2005. Gross LPG production increased from approximately 3,000 gross bpd to 19,000 gross bpd (11,000 bpd net to Marathon). Liquid hydrocarbon production continues to increase as a result of the expansion projects. Total production available for sale in January 2006 was approximately 90,000 gross bpd (51,000 bpd net to Marathon).

Approximately 130 mmcfd of dry gas remaining after the condensate and LPG are removed is supplied to Atlantic Methanol Production Company LLC (AMPCO), where it is used to manufacture methanol. We own 45 percent of AMPCO, which is reported in the Integrated Gas segment. Remaining dry gas is returned offshore and reinjected into the Alba reservoir for later production when the LNG plant construction project on Bioko Island, discussed below under Integrated Gas, is completed.

Libya We hold a 16.33 percent interest in the Waha concessions, which currently produce approximately 350,000 gross boe per day and encompass almost 13 million acres located in the Sirte Basin. As a result of our return to operations in Libya, we expect to add approximately 40,000 to 45,000 net bpd of production available for sale during 2006.

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 12,100 bpd of liquid hydrocarbons in 2005, compared with 13,600 bpd in 2004. Production from these three fields is processed on a single 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 (KMOC). KMOC s fields are located in the Khanty Mansiysk region of western Siberia. Net liquid hydrocarbon sales from these assets averaged 26,600 bpd during 2005, primarily from the East Kamennoye and Potenay fields. Development activities continued in 2005, with 82 wells drilled in East Kamennoye.

Other Matters

We hold an interest in an exploration and production license in Sudan. We suspended operations in Sudan in 1985. We have had no employees in the country and have derived no economic benefit from those interests since that time.

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.

We discovered the Ash Shaer and Cherrife gas fields in Syria in the 1980s. We submitted four plans of development to the Syrian Petroleum Company in the 1990s, but none were approved. The Syrian government subsequently claimed that the production sharing contract for these fields had expired. We have been involved in an ongoing dispute with the Syrian Petroleum Company and government of Syria over our interest in these fields. We are discussing a settlement under which a new production sharing contract would be executed to provide us the right to sell all or a significant portion of our interest to a third party. We have and will continue to comply with all U.S. sanctions related to Syria.

The above discussion of the E&P segment includes forward-looking statements with respect to the timing of completion of the Gudrun appraisal well, the possibility of developing Blocks 31 and 32 offshore Angola, the timing and levels of production from the Neptune development, the Perseus discovery, the combined Alvheim/Vilje development and estimated levels of production associated with our re-entry into Libya. Some factors which could affect the timing of completion of the Gudrun appraisal well, the possible development of Blocks 31 and 32, the timing and production levels of the Neptune development, the Perseus discovery, the Alvheim/Vilje development and estimated levels of production in Libya include pricing, supply and demand for petroleum products, amount of capital available for exploration and development, regulatory constraints, drilling rig availability, inability or delays in obtaining necessary government or third-party approvals or permits, timing of commencing production from new wells, unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response, and other geological, operating and economic considerations. The estimated levels of production in Libya and 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 foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

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Reserves

At December 31, 2005, our net proved liquid hydrocarbon and natural gas reserves totaled approximately 1.295 billion boe, of which 44 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		
	2005	2004	2003	**2005**	2004	2003
Liquid Hydrocarbons *(Millions of Barrels)*						
United States	**165**	171	193	**189**	191	210
Europe	**39**	41	47	**98**	107	59
Africa	**368**	147	120	**373**	223	218
Other International	**31**	27	31	**44**	39	89
Total Consolidated	**603**	386	391	**704**	560	576
Equity Method Investees			2			2
WORLDWIDE	**603**	386	393	**704**	560	578
Developed reserves as a percent of total net proved reserves	**86%**	69%	68%			
Natural Gas *(Billions of Cubic Feet)*						
United States	**943**	992	1,067	**1,209**	1,364	1,635
Europe	**326**	376	421	**486**	544	484
Africa	**638**	570	528	**1,852**	1,564	665
WORLDWIDE	**1,907**	1,938	2,016	**3,547**	3,472	2,784
Developed reserves as a percent of total net proved reserves	**54%**	56%	72%			
Total BOE *(Millions of Barrels)*						
United States	**322**	336	371	**390**	418	483
Europe	**93**	104	117	**179**	198	139
Africa	**475**	242	208	**682**	484	329
Other International	**31**	27	31	**44**	39	89
Total Consolidated	**921**	709	727	**1,295**	1,139	1,040
Equity Method Investees			2			2
WORLDWIDE	**921**	709	729	**1,295**	1,139	1,042
Developed reserves as a percent of total net proved reserves	**71%**	62%	70%			

Proved developed reserves represented 71 percent of total proved reserves as of December 31, 2005, as compared to 62 percent as of December 31, 2004. Of the 374 million boe of proved undeveloped reserves at year-end 2005, less than 20 percent have been included as proved reserves for more than three years while approximately 18 percent were added during 2005.

During 2005, we added net proved reserves of 282 million boe, excluding 2 million boe of dispositions, while producing 124 million boe. These net additions included 165 million boe as a result of our re-entry into Libya, 50 million boe of extensions, discoveries and other additions, and total revisions of 58 million boe. Of the total net reserve additions, 215 million boe were proved developed and 67 million boe were proved undeveloped. Additionally, we transferred 121 million boe from proved undeveloped to proved developed during 2005. Costs incurred for the periods ended December 31, 2005, 2004 and 2003 relating to the development of proved undeveloped oil and natural gas reserves, were $955 million, $708 million and $780 million. These amounts include our proportionate share of equity method investees costs incurred as these were costs necessary for the development of proved undeveloped reserves. As of December 31, 2005, estimated future development costs relating to the development of proved undeveloped oil and natural gas reserves for the years 2006 through 2008 are projected to be $868 million, $340 million and $175 million.

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The Alba field in Equatorial Guinea had the most significant positive revisions, totaling 47 million boe. Of this volume, 21 million boe was added due to the progress on the Equatorial Guinea LNG project, which will provide a market for the Alba field s natural gas reserves sooner and to a greater extent under the current production sharing contract than was expected when proved reserves were estimated at the end of 2004. At the end of 2005, our total proved reserves associated with the Alba field offshore Equatorial Guinea totaled 505 million boe, or 39 percent of our total proved reserves.

The above estimated quantities of net proved oil and natural gas reserves, estimated future development costs relating to the development of proved undeveloped oil and natural gas reserves and timing of production from development projects are forward-looking statements and are based on a number of assumptions, including (among others) 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 could be different than current estimates.

For additional details of estimated quantities of net proved oil and natural gas 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 2004 and 2003 disclosing the year-end estimated oil and natural gas reserves. We will file a similar report for 2005. 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 approximately 152 bcf of natural gas over the remaining lives of these contracts, which terminate in 2012 and 2018. During 2005, we entered into another agreement with a local utility company which, pending Regulatory Commission of Alaska approval, will obligate us to supply approximately 60 bcf of natural gas between 2009 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 62 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 approximately 190 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 17 to the consolidated financial statements for further discussion of these contracts.

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Oil and Natural Gas Net Sales

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

Net Liquid Hydrocarbon Sales[a][b]

(Thousands of Barrels per Day)	**2005**	2004	2003
United States[c]	**76**	81	107
Europe[d]	**36**	40	41
Africa[d]	**52**	32	27
Other International[d]	**27**	16	10
Total Consolidated Continuing Operations	**191**	169	185
Equity Method Investees		1	6
Worldwide Continuing Operations	**191**	170	191
Discontinued Operations[e]			3
WORLDWIDE	**191**	170	194

Net Natural Gas Sales[b][f]

(Millions of Cubic Feet per Day)	**2005**	2004	2003
United States[c]	**578**	631	732
Europe	**224**	273	262
Africa	**92**	76	66
Total Consolidated Continuing Operations	**894**	980	1,060
Equity Method Investees			13
Worldwide Continuing Operations	**894**	980	1,073
Discontinued Operations[e]			74
WORLDWIDE	**894**	980	1,147

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

(b) Amounts represent net sales after royalties, except for the U.K., Ireland and the Netherlands where amounts are before royalties for the applicable periods.

(c) Amounts represent net sales from leasehold ownership, after royalties and interests of others.

(d) Amounts represent 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.

(e) Amounts represent Marathon s western Canadian operations.

(f) Amounts exclude volumes purchased from third parties for injection and subsequent resale of 38 mmcfd in 2005, 19 mmcfd in 2004 and 23 mmcfd in 2003.

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Productive and Drilling Wells

The following tables set forth productive wells and service wells for each of the last three years and drilling wells as of December 31, 2005.

Gross and Net Wells

2005	Productive Wells[a]							
	Oil		Natural Gas		Service Wells[b]		Drilling Wells[c]	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
United States	**5,724**	**2,029**	**5,254**	**3,696**	**2,723**	**827**	**55**	**31**
Europe	**51**	**19**	**68**	**37**	**29**	**10**	**3**	**1**
Africa	**926**	**155**	**13**	**8**	**97**	**18**	**7**	**1**
Other International	**156**	**156**			**50**	**50**	**26**	**26**
WORLDWIDE	**6,857**	**2,359**	**5,335**	**3,741**	**2,899**	**905**	**91**	**59**

2004	Productive Wells[a]					
	Oil		Natural Gas		Service Wells[b]	
	Gross	Net	Gross	Net	Gross	Net
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

2003	Productive Wells[a]					
	Oil		Natural Gas		Service Wells[b]	
	Gross	Net	Gross	Net	Gross	Net
United States	5,580	2,040	4,649	3,555	2,726	834
Europe	52	14	65	35	27	9
Africa	7	4	10	7	1	1
Other International	109	109			21	21

Total Consolidated	5,748	2,167	4,724	3,597	2,775	865
Equity Method Investees	96	21			15	3
WORLDWIDE	5,844	2,188	4,724	3,597	2,790	868

(a) Includes active wells and wells temporarily shut-in. Of the gross productive wells, gross wells with multiple completions operated by Marathon totaled 278 in 2005, 273 in 2004 and 273 in 2003. Information on wells with multiple completions operated by other companies is unavailable to Marathon.

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

(c) Consists of exploratory and development wells.

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Drilling Activity

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

Net Productive and Dry Wells Completed[(a)]

			2005	2004	2003
United States					
	Development [(b)]	Oil	**46**	13	4
		Natural Gas	**288**	167	231
		Dry	**4**		
		Total	**338**	180	235
	Exploratory	Oil	**2**	1	1
		Natural Gas	**17**	8	7
		Dry	**2**	6	2
		Total	**21**	15	10
		Total United States	**359**	195	245
International					
	Development [(b)]	Oil	**68**	27	31
		Natural Gas	**2**	3	14
		Dry	**1**	1	1
		Total	**71**	31	46
	Exploratory	Oil	**2**	2	2
		Natural Gas			21
		Dry	**4**	7	5
		Total	**6**	9	28
		Total International	**77**	40	74
WORLDWIDE			**436**	235	319

(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, 2005:

Gross and Net Acreage

(Thousands of Acres)	**Developed**		**Undeveloped**		**Developed and Undeveloped**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
United States	1,459	910	2,894	1,415	4,353	2,325
Europe	395	305	968	393	1,363	698
Africa	12,971	2,149	2,951	769	15,922	2,918
Other International	599	599	2,541	1,997	3,140	2,596
WORLDWIDE	15,424	3,963	9,354	4,574	24,778	8,537

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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 974,000 barrels of crude oil per day. The table below sets forth the location and daily throughput capacity of each of our refineries as of December 31, 2005:

Crude Oil Refining Capacity

(Barrels per Day)	
Garyville, Louisiana	245,000
Catlettsburg, Kentucky	222,000
Robinson, Illinois	192,000
Detroit, Michigan	100,000
Canton, Ohio	73,000
Texas City, Texas	72,000
St. Paul Park, Minnesota	70,000
TOTAL	974,000

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. Our refineries are integrated via pipelines and barges to maximize operating efficiency. The transportation links that connect the 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.

We increased our overall crude oil refining capacity during 2005 from 948,000 bpd to 974,000 bpd after completing the expansion project at our Detroit refinery. This expansion increased crude oil capacity at Detroit from 74,000 bpd to 100,000 bpd. The project also improves operating efficiency and enables the Detroit refinery to meet new lower gasoline and diesel sulfur specifications.

During 2005, we announced plans to evaluate a 180,000 bpd expansion of our Garyville refinery. The initial phase of the potential expansion includes front-end engineering and design (FEED) work which began in December 2005 and could lead to the start of construction in 2007. The project, estimated to cost approximately $2.2 billion, could be completed as early as the fourth quarter of 2009. The final investment decision is subject to completion of the FEED work and the receipt of applicable permits.

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.

During 2005, our refineries processed 973,000 bpd of crude oil and 205,000 bpd of other charge and blend stocks. 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)	**2005**	2004	2003
Gasoline	**644**	608	567

Distillates	**318**	299	284
Propane	**21**	22	21
Feedstocks and Special Products	**96**	94	93
Heavy Fuel Oil	**28**	25	24
Asphalt	**85**	77	72
TOTAL	**1,192**	1,125	1,061

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Planned maintenance activities requiring temporary shutdown of certain refinery operating units, or turnarounds, are periodically performed at each refinery. We completed major turnarounds at our Detroit and Catlettsburg refineries in 2005.

Marketing

In 2005, our refined product sales volumes (excluding matching buy/sell transactions) totaled 21.1 billion gallons (1,378,000 bpd). The wholesale distribution of petroleum products to private brand marketers and to large commercial and industrial consumers, primarily located in the Midwest, the upper Great Plains and the Southeast, and sales in the spot market, accounted for approximately 71 percent of our refined product sales volumes in 2005, excluding sales related to matching buy/sell transactions. Approximately 53 percent of our gasoline sales volumes and 91 percent of our distillate sales volumes were sold on a wholesale or spot market basis.

Approximately 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 the Southeast. Our customer base includes approximately 830 asphalt-paving contractors, government entities (states, counties, cities and townships) and asphalt roofing shingle manufacturers.

The following table sets forth our refined product sales by product group for each of the last three years:

Refined Product Sales

(Thousands of Barrels per Day)	**2005**	2004	2003
Gasoline	**836**	807	776
Distillates	**385**	373	365
Propane	**22**	22	21
Feedstocks and Special Products	**96**	92	97
Heavy Fuel Oil	**29**	27	24
Asphalt	**87**	79	74
TOTAL	**1,455**	1,400	1,357
Matching Buy/ Sell Volumes included in above	**77**	71	64

We sell reformulated gasoline in parts of our marketing territory, primarily Chicago, Illinois; Louisville, Kentucky; northern Kentucky; and Milwaukee, Wisconsin. We also sell low-vapor-pressure gasoline in nine states.

As of December 31, 2005, we supplied petroleum products to about 4,000 Marathon branded retail outlets located primarily in Michigan, Ohio, 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.

SSA sells gasoline and diesel fuel through company-operated retail outlets. As of December 31, 2005, SSA had 1,638 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 $2.5 billion in 2005, compared with $2.3 billion in 2004. 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 approximately 260 locations in 37 states at December 31, 2005. The travel centers offer diesel fuel, gasoline and a variety of other services, including on-premises brand-name restaurants. Pilot and

Marathon each own a 50 percent interest in PTC.

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

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Supply and Transportation

We obtain the crude oil we process from negotiated contracts and spot purchases or exchanges. In 2005, our net purchases of U.S. produced crude oil for refinery input averaged 447,000 bpd, or 46 percent of crude oil processed, including a net 12,000 bpd from our production operations. In 2005, Canada was the source for 11 percent, or 111,000 bpd, of crude oil processed and other foreign sources supplied 43 percent, or 415,000 bpd, of the crude oil processed by our refineries, including approximately 221,000 bpd from the Middle East. This crude was acquired from various foreign national oil companies, producing companies and trading companies.

We operate a system of pipelines and terminals to provide crude oil to our refineries and refined products to our marketing areas. At December 31, 2005, we owned or leased approximately 2,774 miles of crude oil trunk lines and 3,824 miles of refined product trunk lines. At December 31, 2005 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;

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

51 percent interest in LOOP LLC (LOOP), which is the owner and operator of the only U.S. deepwater oil port, located 18 miles off the coast of Louisiana;

59 percent interest in LOCAP LLC, which owns a crude oil pipeline connecting LOOP and the Capline system;

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

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

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

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

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

Our 85 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/or trucks. Our marine transportation operations include towboats and barges that transport refined products on the Ohio, Mississippi and Illinois rivers, their tributaries and the Intercoastal Waterway. We also lease and own rail cars of various sizes and capacities for movement and storage of petroleum products and a large number of tractors and tank trailers.

Effective October 15, 2006, most of the diesel fuel sold for highway use must contain no more than 15 parts per million of sulfur at the retail outlet. This new ultra low sulfur diesel (ULSD) fuel requirement will place a premium on ensuring that there is no contamination of the ULSD while it is in transit to the retail outlet. We expect to be able to meet these requirements.

The above discussion of the RM&T segment includes forward-looking statements concerning the possible expansion of the Garyville refinery. Some factors that could affect the Garyville expansion project include the results of the FEED work, necessary regulatory approvals, crude oil supply and transportation logistics, necessary permits and continued favorable investment climate, availability of materials and labor, unforeseen hazards such as weather conditions and other risks customarily associated with construction projects. These factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

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Integrated Gas

Our integrated gas operations include natural gas liquefaction and regasification operations, methanol operations, certain other gas processing facilities and pipeline operations, and marketing and transportation of natural gas. Also included in the financial results of the Integrated Gas segment are the costs associated with ongoing development of certain integrated gas projects.

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 2005 LNG deliveries totaling 65 gross bcf (22 net bcf).

Equatorial Guinea LNG Project

In 2004, we and our partner, Compania Nacional de Petroleos de Guinea Ecuatorial (GEPetrol), the National Oil Company of Equatorial Guinea, through Equatorial Guinea LNG Holdings Limited (EGHoldings), began construction of an LNG plant on Bioko Island that will initially deliver a contracted offtake of 3.4 million metric tons per year beginning in 2007 (approximately 460 mmcfd) under a Sales and Purchase Agreement with a subsidiary of BG Group plc (BGML). BGML will purchase the LNG plant s production for a period of 17 years on an FOB Bioko Island basis with pricing linked principally to the Henry Hub index. The LNG plant is ultimately expected to have the ability to operate at higher rates and for a longer period than the current contracted offtake rate and term. This project will allow us to monetize our natural gas reserves from the Alba field, as natural gas for the plant will be purchased from the Alba field participants under a long-term natural gas supply agreement. Construction of the plant is ahead of schedule with first shipment of LNG expected in the third quarter of 2007.

On July 25, 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, respectively, in EGHoldings. Following the transaction, we hold a 60 percent interest in EGHoldings, with GEPetrol holding a 25 percent interest and Mitsui and Marubeni holding the remaining interests.

The EGHoldings partners are also exploring the feasibility of adding a second LNG train in an effort to create a regional gas hub that would commercialize stranded natural gas from various sources in the surrounding Gulf of Guinea region.

Elba Island LNG

In April 2004, we began delivering LNG cargoes as part of our Elba Island, Georgia LNG regasification terminal capacity rights agreement. Under the terms of the agreement, we can supply up to 58 billion cubic feet of natural gas (as LNG) per year into the terminal through 2021 with a possible extension to 2023.

In September 2004, we signed an agreement with BP Energy Company (BP) under which BP will supply us 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 with BP enables us to fully utilize our capacity rights at Elba Island during the period of this agreement, while affording us the flexibility to access this capacity to commercialize other stranded natural gas resources beyond the term of the BP contract. The agreement commenced in 2005.

Methanol

We own a 45 percent interest in Atlantic Methanol Production Company LLC (AMPCO), which owns a methanol plant located in Malabo, Equatorial Guinea. Feedstock for the plant is supplied from a portion of our natural gas production in the Alba field. Methanol sales totaled 1,052,000 gross metric tons (473,000 net metric tons) in 2005. Production from the plant is used to supply customers in Europe and the U.S.

AMPCO will undergo a scheduled maintenance shutdown during the second quarter of 2006. During the outage, AMPCO will also seek to remove bottlenecks in several parts of the plant.

Natural Gas Marketing and Transportation Activities

In addition to the sale of our own natural gas production, we purchase gas from third-party producers and marketers for resale.

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During 2005, we sold our 24 percent interest in Nautilus Pipeline Company, LLC and our 24 percent interest in Manta Ray Offshore Gathering Company, LLC, which are both Gulf of Mexico natural gas pipeline systems. We still own a 34 percent interest in the Neptune natural gas processing plant located in St. Mary Parish, Louisiana. The plant has the capacity to process 600 mmcfd of natural gas, which is supplied by the Nautilus pipeline system.

Gas Technology

We invest in gas technology research, including gas-to-liquids (GTL) technology which was successfully applied in a GTL demonstration plant at the Port of Catoosa, Oklahoma in 2004. In addition to GTL, we are continuing to explore gas technologies including methanol to power, gas to fuels and compressed natural gas technologies.

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 plant and the possible expansion thereof. Factors that could affect the LNG plant include, unforeseen problems arising from construction, inability or delay in obtaining necessary government and third-party approvals, unanticipated changes in market demand or supply, environmental issues, availability or construction of sufficient LNG vessels, and unforeseen hazards such as weather conditions. In addition to these factors, other factors that could potentially affect the possible expansion of the current LNG project 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 for the acquisition of oil and natural gas leases and other properties. We compete with these companies, as well as national oil 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. As a consequence, we may be at a competitive disadvantage in bidding for the rights to explore for oil and natural gas. 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 believe 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, 2005. We compete in four distinct markets wholesale, spot, branded and retail distribution for the sale of refined products. We believe we compete with about 30 companies in the wholesale distribution of petroleum products to private brand marketers and large commercial and industrial consumers; about 75 companies in the sale of petroleum products in the spot market; nine refiner/marketers in the supply of branded petroleum products to dealers and jobbers; and approximately 220 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[tm]. 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 refining and marketing margins 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.

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As a result of the Separation, Marathon and United States Steel are separate companies, and neither has any ownership interest in the other. Effective January 31, 2006, Thomas J. Usher retired as chairman of the board of directors and as a director of United States Steel, and Dr. Shirley Ann Jackson retired as a director of United States Steel. As a result, three remaining members of our board of directors are also directors of United States Steel.

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

Financial Matters Agreement

Under the financial matters agreement, United States Steel has assumed and agreed to discharge all 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 shall have the right to exercise all of the existing contractual rights under the lease obligations assumed from Marathon, including all rights related to purchase options, prepayments or the grant or release of security interests. United States Steel shall have 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 lease obligations.

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 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 take all necessary action or refrain from acting so as to assure compliance with all covenants and other obligations under the documents relating to the assumed obligations to avoid the occurrence of a default or the acceleration of the payment obligations under 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.

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Tax Sharing Agreement

Marathon and United States Steel have a tax sharing agreement that applies to each of their consolidated tax reporting groups. Provisions of this agreement include the following:

- for any taxable period, or any portion of any taxable period, ended on or before December 31, 2001, unpaid tax sharing payments will be made between Marathon and United States Steel generally in accordance with the general tax sharing principles in effect before the Separation;

- no tax sharing payments will be made with respect to taxable periods, or portions thereof, beginning after December 31, 2001; and

- provisions relating to the tax and related liabilities, if any, that result from the Separation ceasing to qualify as a tax-free transaction and limitations on post-Separation activities that might jeopardize the tax-free status of the Separation.

Under the general tax sharing principles in effect before the Separation:

- the taxes payable by each of the Marathon Group and the U.S. Steel Group were determined as if each of them had filed its own consolidated, combined or unitary tax return; and

- the U.S. Steel Group would receive the benefit, in the form of tax sharing payments by the parent corporation, of the tax attributes, consisting principally of net operating losses and various credits, that its business generated and the parent used on a consolidated basis to reduce its taxes otherwise payable.

In accordance with the tax sharing agreement, at the time of the Separation, Marathon made a preliminary settlement with United States Steel of approximately $440 million as the net tax sharing payments owed to it for the year ended December 31, 2001 under the pre-Separation tax sharing principles.

The tax sharing agreement also addresses the handling of tax audits and contests and other matters respecting taxable periods, or portions of taxable periods, ended before December 31, 2001.

In the tax sharing agreement, each of Marathon and United States Steel promised the other party that it:

- would not, before January 1, 2004, take various actions or enter into various transactions that might, under section 355 of the Internal Revenue Code of 1986, jeopardize the tax-free status of the Separation; and

- would be responsible for, and indemnify and hold the other party harmless from and against, any tax and related liability, such as interest and penalties, that results from the Separation ceasing to qualify as tax-free because of its taking of any such action or entering into any such transaction.

The prescribed actions and transactions include:

- the liquidation of Marathon or United States Steel; and

- the sale by Marathon or United States Steel of its assets, except in the ordinary course of business.

In case a taxing authority seeks to collect a tax liability from one party that the tax sharing agreement has allocated to the other party, the other party has agreed in the sharing agreement to indemnify the first party against that liability.

Even if the Separation otherwise qualified for tax-free treatment under section 355 of the Internal Revenue Code, the Separation may become taxable to Marathon under section 355(e) of the Internal Revenue Code if capital stock representing a 50 percent or greater interest in either Marathon or United States Steel is acquired, directly or indirectly, as part of a plan or series of related transactions that include the Separation. For this purpose, a 50 percent or greater interest means capital stock possessing at least 50 percent of the total combined voting power of all classes of stock entitled to vote or at least 50 percent of the total value of shares of all classes of capital stock. To minimize this risk, both Marathon and United States Steel agreed in the tax sharing agreement that they would not enter into any transactions or make any change in their equity structures that could cause the Separation to be treated as part of a plan or series of related transactions to which those provisions of section 355(e) of the Internal Revenue Code may apply. If an acquisition occurs that results in the Separation being taxable under section 355(e) of the Internal Revenue

Code, the agreement provides that the resulting corporate tax liability will be borne by the party involved in that acquisition transaction.

Although the tax sharing agreement allocates tax liabilities relating to taxable periods ending on or prior to the Separation, each of Marathon and United States Steel, as members of the same consolidated tax reporting group during any portion of a taxable period ended on or prior to the date of the Separation, is jointly and severally liable under the Internal Revenue Code for the federal income tax liability of the entire consolidated tax reporting group for that year. To address the possibility that the taxing authorities may seek to collect all or part of a tax liability from one party where the tax sharing agreement allocates that liability to the other party, the agreement includes

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indemnification provisions that would entitle the party from whom the taxing authorities are seeking collection to obtain indemnification from the other party, to the extent the agreement allocates that liability to that other party. Marathon can provide no assurance, however, that United States Steel will be able to meet its indemnification obligations, if any, to Marathon that may arise under the tax sharing agreement.

Obligations Associated with the Separation as of December 31, 2005

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 Marathon s obligations associated with the Separation.

Environmental Matters

We maintain a comprehensive environmental policy overseen by the Corporate Governance and Nominating Committee of our Board of Directors. 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. The Corporate Responsibility Management Committee, which is comprised of certain of our officers, is charged with reviewing 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 incident involving Marathon or any of our properties.

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 are U.S. Environmental Protection Agency (EPA) regulations that require reduced sulfur levels starting in 2004 for gasoline and 2006 for diesel fuel. Our combined capital costs to achieve compliance with these rules are expected to approximate $900 million over the period between 2002 and 2006, which includes costs that could be incurred as part of other refinery upgrade projects. Costs incurred through December 31, 2005 were approximately $825 million, with the remainder expected to be incurred in 2006. This is a forward-looking statement. Some factors (among others) that could potentially affect gasoline and diesel fuel compliance costs include completion of construction and start-up activities.

The EPA has finalized new and revised National Ambient Air Quality Standards (NAAQS) for fine particulate emissions (PM2.5) 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 SO_2 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.

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Water

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

Additionally, OPA-90 requires that new tank vessels entering or operating in U.S. waters be double hulled and that existing tank vessels that are not double-hulled be retrofitted or removed from U.S. service, according to a phase-out schedule. As of December 31, 2005, all of the barges used for river transport of our feedstocks 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 some 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. Accruals for remediation expenses and associated reimbursements are established for sites where contamination has been determined to exist and the amount of associated costs is reasonably determinable.

Employees

We had 27,756 active employees as of December 31, 2005. Of that number, 18,257 were employees of Speedway SuperAmerica LLC, most of which were employed at 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, 2006 at our St. Paul Park refinery and January 31, 2007 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/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.

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Item 1A. Risk Factors

Marathon is subject to various risks and uncertainties in the course of its business. The following summarizes some, but not all, of the risks and uncertainties that may adversely affect our business, financial condition or results of operations.

A substantial or extended decline in oil or natural gas prices would reduce our revenues, operating results and future rate of growth.

Prices for oil and natural gas 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 and natural gas;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- political instability or armed conflict in oil-producing regions; and
- domestic and foreign governmental regulations and taxes.

The long-term effects of these and other conditions on the prices of oil and natural gas are uncertain.

Lower oil and natural gas prices may reduce the amount of oil and natural gas that we produce, which may reduce our revenues and operating income. Significant reductions in oil and natural gas prices could require us to reduce our capital expenditures.

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 reserve information included in this Report has been derived from engineering estimates. Those estimates were prepared by our personnel and reviewed, on a selected basis, by third-party petroleum engineers. The estimates were calculated using oil and natural gas prices in effect as of December 31, 2005, as well as other conditions in existence as of that date. Any significant future price changes may 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. 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 included in this Report should not be considered as the market value of the reserves attributable to our properties. As required by generally accepted accounting principles, the estimated discounted future net revenues from our proved reserves are based generally 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 that is required to be used to calculate discounted future net revenues for reporting purposes under generally accepted accounting principles is not necessarily the most appropriate discount factor based on the cost of capital in effect from time to time and risks associated with our business and the oil and natural gas industry in general.

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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 additional properties containing proved reserves, conduct successful exploration and development activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, our proved reserves will decline materially as oil and natural gas is produced.

Increases in crude oil prices and environmental regulations may reduce our refined product margins.

The profitability of our refining, marketing and transportation operations depends largely on the margin between the cost of crude oil and other feedstocks 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 margins have been historically 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 refining and marketing operations, which may reduce our refined product 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 natural gas companies for the acquisition of oil and natural gas leases and other properties. We compete with these companies, as well as national oil 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 substantially 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 plants. 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 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, operating results will be adversely affected. The specific impact of these laws and regulations on each of our competitors may vary depending on a number of factors, including the age and location of their operating facilities, marketing area and production processes. We may also be required to make material expenditures or 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 action 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.

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

Local political and economic factors in international markets could have a material adverse effect on us. Approximately 50 percent of our oil and natural gas production in 2005 was derived from production outside the United States and approximately 70 percent of our proved reserves as of December 31, 2005 were located outside the United States. In addition, we are increasing the focus of our development operations on areas 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 or may attempt to renegotiate or revoke existing contractual arrangements; 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 cause a downturn in 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. More specifically, 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 insurance coverages that we consider adequate.

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

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

Our exploration and production operations are subject to unplanned occurrences, including blowouts, explosions, fires, loss of well control, spills, hurricanes and other adverse weather, labor disputes and maritime 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 interruptions, crude oil or refined product spills, inclement weather or labor disputes. They are also subject to the additional hazards of marine operations, such as capsizing, collision and damage or loss from severe weather conditions. 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.

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, Marathon is severally liable for federal income taxes (and in some cases for certain state taxes) for tax years of Ashland 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 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 recently completed transactions with Ashland under the fraudulent transfer provisions of the U.S. Bankruptcy Code and comparable provisions of 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 U.S. Bankruptcy Code and 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 recently completed transactions with Ashland, 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 nevertheless 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 it 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 $597 million as of December 31, 2005, including accrued interest of $9 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 pay federal income taxes, fund its ERISA pension plans and pay other obligations related to periods prior to the effective date of the separation.

United States Steel has non-investment grade credit ratings and has granted security interests in some of its assets. 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,

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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 and gas plants, 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, management believes 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

Marathon was 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 first case, U.S. ex rel Jack J. Grynberg v. Alaska Pipeline Co., et al is primarily a gas measurement case and the second case, U.S. ex rel Harrold E. Wright v. Agip Petroleum Co. et al, is primarily a gas valuation case. These cases assert that false claims have been filed by lessees and that penalties, damages and interest total more than $25 billion. 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. In the Grynberg case, the parties have briefed and argued their motions regarding whether the District Court should adopt the recommendations of the Magistrate which would dismiss Marathon and many other defendants on jurisdictional grounds. The Wright case is in the discovery phase. 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 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.

Acquisition Litigation

On April 8, 2005, Shiva Singh instituted a class action in the Supreme Court of the State of New York in New York County against Ashland, and the individual members of Ashland s Board of Directors. The complaint also named Marathon, MPC and Credit Suisse First Boston LLC (CSFB) as defendants. The complaint stated that Mr. Singh held Ashland common stock and that the complaint was brought on behalf of Mr. Singh and others similarly situated. The action arose from the transaction proposed at that time in which Ashland would transfer its entire 38 percent interest in MPC as well as certain other businesses to Marathon. The complaint alleged breach of fiduciary duty as well as aiding and abetting breach of fiduciary duty and negligence against Ashland, its directors, Marathon and MPC. The complaint alleged breach of fiduciary duty and negligence as well as aiding and abetting breach of fiduciary duty and negligence against CSFB.

On September 20, 2005, the federal judge entered an order dismissing certain of the plaintiff s negligence claims against CSFB and the aiding and abetting claims against all defendants and directed the court clerk to mark the case closed. This case is not currently pending.

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

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personal and real property damages. Plaintiffs seek class action status. In 2002, MPC conducted extensive cleaning operations at affected facilities but 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

The following is a summary of proceedings involving Marathon that were pending or contemplated as of December 31, 2005 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.

Projections, provided in the following paragraphs, of spending for and/or timing of completion of specific projects 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.

At December 31, 2005, Marathon had been identified as a PRP at a total of seven 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, and most will be under $100,000. Marathon believes that its liability for cleanup and remediation costs in connection with the one remaining site will be under $3 million.

In addition, there is one site where Marathon has received information requests or other indications that it may be a PRP under CERCLA but where sufficient information is not presently available to confirm the existence of liability.

There are also 123 additional 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 29 of these sites will be under $100,000 per site, 51 sites have potential costs between $100,000 and $1 million per site and 18 sites may involve remediation costs between $1 million and $5 million per site. Nine sites have incurred remediation costs of more than $5 million per site and there are 16 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 five years, Marathon anticipates spending approximately $5 million at this site. Appropriate site characterization and risk-based assessments necessary for closure will be refined during 2006 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 2005 were approximately $540,000, with expenditures in 2006 expected to be $1 million.

MPC has had a pending enforcement matter with the Illinois Environmental Protection Agency and the Illinois Attorney General s Office since 2002 concerning its self-reporting of possible emission exceedences and permitting issues related to storage tanks at its Robinson, Illinois refinery. MPC anticipates more discussions with Illinois officials in 2006.

In August of 2004, the West Virginia Department of Environmental Protection (WVDEP) submitted a draft consent order to MPC regarding its handling of alleged hazardous waste generated from tank cleanings in the State of

West Virginia. The proposed order sought a civil penalty of $337,900. MPC resolved this matter in 2005 by entering an administrative order with WVDEP where no civil penalty was imposed but MPC agreed to pay $95,297 as an administrative settlement, a contribution to the State Department of Natural Resources for park remediation efforts unrelated to this matter and a reimbursement of WVDEP s costs.

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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 has been voluntarily producing 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 have already been produced or that are in the process of being identified and produced in response to the SEC s prior requests, and requesting 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 and the Pacific 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, 2006, there were 67,230 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, 2005 of equity securities that are registered by Marathon pursuant to Section 12 of the Exchange Act:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares Purchased[(a)(b)]	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
10/01/05 10/31/05	13,159	$ 59.00	N/A	N/A
11/01/05 11/30/05	2,219	$ 60.86	N/A	N/A
12/01/05 12/31/05	21,196[(c)]	$ 61.78	N/A	N/A

Total	36,574	$ 60.73	N/A	N/A

[a] 15,566 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 6 shares due to Acquisition exchanges and Ashland share transfers pending at the time of closing of the Acquisition.

[c] 21,002 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.

Item 6. Selected Financial Data

See page F-52.

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

Marathon is engaged in worldwide exploration and production 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 natural gas and products manufactured from natural gas, such as LNG and methanol. 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, 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 MPC include the 38 percent interest held by Ashland prior to the Acquisition on June 30, 2005, and amounts for EGHoldings include the 25 percent interest held by GEPetrol, and the 8.5 percent interest held by Mitsui and the 6.5 percent interest held by Marubeni subsequent to July 25, 2005.

Overview

Exploration and Production

Exploration and production segment revenues correlate closely with prevailing prices for the various qualities of crude oil and natural gas produced. The increase in our E&P segment revenues during 2005 tracked the increase in prices for these commodities. Higher prices for crude oil during 2005 reflected concerns about international supply and hurricane damage in the U.S. Gulf of Mexico. The average spot price during 2005 for West Texas Intermediate (WTI), a benchmark crude oil, was $56.70 per barrel, up from an average of $41.47 in 2004, and ended the year at $61.04. The average differential between WTI and Brent (an international benchmark crude oil) narrowed to $2.18 in 2005 from $3.20 in 2004. Our domestic crude production is on average heavier and higher in sulfur content than light sweet WTI. Heavier and higher sulfur crude oil (commonly referred to as sour crude) sells at a discount to light sweet crude oil. The majority of OPEC spare capacity and new production worldwide is medium sour or heavy sour, so the discount for medium and heavy sour crudes has increased relative to light sweet crude and thus reduced the relative profitability of sour crude production. Outside of Russia, our international crude production is relatively sweet and is generally sold in relation to the Brent crude benchmark.

Natural gas prices were also higher in 2005 compared to 2004. 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. Our natural gas prices in Alaska are largely contractual, while natural gas production there is seasonal in nature, trending down during the second and third quarters 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 price risk management, see Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

E&P segment income during 2005 was up approximately 76 percent from 2004 levels, impacted by higher product prices as discussed above and increased liquid hydrocarbon sales volumes. We estimate that our 2006 production available for sale will average approximately 365,000 to 395,000 boe per day, excluding the impact of acquisitions and dispositions. This includes an estimated 40,000 to 45,000 boe per day as a result of our return to operations in the Waha concessions in Libya. With the developments we have under construction, we estimate our production will grow to 475,000 to 525,000 boe per day by 2008, excluding acquisitions and divestitures.

Projected production levels for liquid hydrocarbons and natural gas are based on a number of assumptions, including (among others) pricing, supply and demand for petroleum products, the amount of capital available for exploration and development, regulatory constraints, 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 thereto, and other geological, operating and economic considerations. These assumptions may prove to be inaccurate. Prices have historically been volatile and have frequently been driven by unpredictable changes in supply and demand resulting from fluctuations in economic activity and political developments in the world s major oil and gas producing areas, including OPEC member countries. Any substantial decline in such prices could have a material adverse effect on our results of operations. A decline in such prices could also adversely affect the quantity of liquid hydrocarbons and natural gas that can be economically produced and the amount of capital available for exploration and development.

Refining, Marketing and Transportation

We refine, market and transport crude oil and petroleum products, primarily in the Midwest, upper Great Plains and southeastern United States. RM&T segment income depends largely on our refining and wholesale marketing margin, refinery throughputs, retail marketing margins for gasoline, distillates and merchandise, and the profitability of our pipeline transportation operations.

The refining and wholesale marketing margin is the difference between the wholesale prices of refined products sold and the cost of crude oil and other feedstocks refined, the cost of purchased products and manufacturing costs. We purchase crude oil to satisfy our refineries throughput requirements. As a result, our refining and wholesale marketing margin could be adversely affected by rising crude oil and other feedstock 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 costs, is an industry indicator of refining margins. In addition to changes in the crack spread, our refining and wholesale marketing margin is impacted by the types of crude oil we process, the wholesale selling prices we realize for all the products we sell 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 the largest U.S. producer of asphalt, our refining and wholesale marketing margin is significantly 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. 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. Finally, our refining and wholesale marketing 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. Our refining and wholesale marketing margin has been historically volatile and varies with the level of economic activity in our various marketing areas, the regulatory climate, logistical capabilities and the expectations regarding the adequacy of the supply of refined products and raw materials.

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

Our retail marketing margin for gasoline and distillates, which is the difference between the ultimate price paid by consumers and the wholesale cost of the refined products, including secondary transportation, also plays an important part in RM&T profitability. Factors affecting our retail gasoline and distillate 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 margin from the retail sale of gasoline and diesel fuel. 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 throughput of the 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, and declines during the fall and winter months. The seasonal pattern for distillates is the reverse of this, helping to level overall variability on an annual basis. As with crude oil, other transportation alternatives and system maintenance levels influence refined product movements.

Integrated Gas

Our integrated gas strategy is to link stranded natural gas resources with areas where a supply gap is emerging due to declining production and growing demand. LNG, particularly in regard to our operations in Equatorial Guinea, is a key component of that integrated gas strategy. Our integrated gas operations include marketing and transportation of natural gas and 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. The profitability of these operations depends largely on commodity prices, volume deliveries, margins on resale gas, and demand. Methanol spot pricing is volatile largely because global methanol demand is only 33 million tons and any major unplanned shutdown of or addition to production capacity can have a significant impact on the supply-demand balance.

2005 Operating Highlights

- We achieved exploration success with eight discoveries from 11 significant wells. We strengthened core E&P areas by:
  - re-entering our operations in Libya;
  - completing the Equatorial Guinea liquefied petroleum gas plant expansion project;
  - progressing the Alvheim development offshore Norway to 43 percent completion; and
  - obtaining approval for the Neptune development in the deepwater Gulf of Mexico.
- We added net proved oil and natural gas reserves of 282 million boe, excluding 2 million boe of dispositions, while producing 124 million boe during 2005. Over the past three years, we have added net proved reserves of 675 million boe, excluding dispositions of approximately 277 million boe, while producing approximately 385 million boe.
- We strengthened our RM&T business by:
  - acquiring full ownership of our RM&T operations, with our acquisition of the 38 percent interest previously held by Ashland;
  - completing the 26,000 bpd expansion of our Detroit refinery; and
  - initiating FEED work for a potential 180,000 bpd expansion of our Garyville, Louisiana refinery.
- We achieved same store merchandise sales growth of 11.7 percent at Speedway SuperAmerica in 2005, which is the third consecutive year of double digit merchandise sales growth, and same store gasoline sales volume growth of 4.0 percent, which is the fourth consecutive year of better than one percent volume growth.
- We advanced our integrated gas strategy by:
  - accelerating the EG LNG plant construction, such that the project is 66 percent complete at the end of 2005 with the first LNG shipments projected for the third quarter of 2007; and
  - initiating an LNG supply contract to utilize our Elba Island, Georgia re-gasification terminal access rights.
- We increased the quarterly dividend 18 percent to 33 cents per share.

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 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 2005, net revisions of previous estimates increased total proved reserves by 58 million boe (five percent of the beginning-of-the-year reserves estimate). Positive revisions of 82 million boe were partially offset by 24 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 approved by members of our Corporate Reserves Group. Any revisions of proved reserves estimates in excess of 2.5 million boe on a total-field basis must be approved by the Director of Corporate Reserves, who reports to our Chief Financial Officer. The Corporate Reserves Group audits recent acquisitions of material fields and properties with problematic indicators such as excessively long lives, sudden changes in performance or changes in economic or operating conditions. In addition, third-party consultants are engaged to audit reserve estimates with the stated objective of reviewing the top 80 percent of our reserves over a three-year period. Third-party audits did not result in any significant changes to reserve estimates during 2005, 2004 and 2003.

The reserves of the Alba field offshore Equatorial Guinea comprise approximately 39 percent of our total proved oil and natural gas reserves as of December 31, 2005. The reserves of the Waha concession in Libya that were acquired at the end of 2005 comprise approximately 13 percent of our total proved oil and natural gas reserves at that date. The next five largest oil and gas producing asset groups the Alvheim development offshore Norway, the Brae Area Complex offshore the United Kingdom (U.K.), the Kenai field in Alaska, the Petronius development in the Gulf of Mexico and the East Kamennoye license in Russia comprise a total of approximately 15 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 $6.04 per barrel to $5.75 per barrel, which would increase pretax income by approximately $36 million annually, based on 2005 production. A five percent decrease in the amount of oil and natural gas reserves would change the depreciation and depletion rate from $6.04 per barrel to $6.36 per barrel and would result in a decrease in pretax income of approximately $40 million annually, based on 2005 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, to assess impairment of long-lived assets and goodwill and to record non-exchange traded derivative instruments. Other items which require estimates of fair value 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 $3.153 billion that was allocated to the assets acquired and liabilities assumed based on their estimated fair values. See Note 5 to the consolidated financial statements for information on these acquisitions. As of December 31, 2005, we have recorded goodwill of $1.307 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 carrying value.

The fair values used to allocate the purchase prices of acquisitions 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 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 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.

We did not have significant impairment charges during 2005 or 2003. 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 U.K. which 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 for the next eighteen months under these contracts. 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. The non-cash losses related to changes in fair value recognized in income from operations were $386 million in 2005, $99 million in 2004, and $66 million in 2003. These effects are primarily due to the U.K. 18-month forward natural gas price curve strengthening 90 percent, 36 percent and 26 percent during 2005, 2004 and 2003, respectively.

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, 2005, we reported deferred tax assets of $1.782 billion, which represented gross assets of $2.409 billion net of valuation allowances of $627 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.

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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:

discount rate for measuring the present value of future plan obligations;

expected long-term rates of return on plan assets;

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 nine 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 U.S. 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.

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 23 to the consolidated financial statements includes detailed information for the three years ended December 31, 2005, on the components of pension and other postretirement benefit expense and the underlying assumptions.

Of the assumptions used to measure the December 31, 2005 obligations and estimated 2006 net periodic benefit cost, the discount rate has the most significant effect on the periodic benefit costs reported for the plans. A ..25 percent decrease in the discount rates of 5.50 percent for our domestic pension plan and 5.75 percent for our domestic postretirement benefit plan would increase pension expense and other postretirement benefit plan expense by approximately $13 million and $3 million, respectively.

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 approximately $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 as to the sensitivity to earnings 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

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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 Income and Operations

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

(In millions)	**2005**	2004	2003
E&P	**$ 6,486**	$ 4,996	$ 4,877
RM&T	**56,003**	43,630	34,514
IG	**2,084**	1,739	2,248
Segment revenues	**64,573**	50,365	41,639
Elimination of intersegment revenues	**(876)**	(668)	(610)
Loss on long-term U.K. gas contracts	**(386)**	(99)	(66)
Total revenues	**$ 63,311**	$ 49,598	$ 40,963
Items included in both revenues and costs and expenses:			
Consumer excise taxes on petroleum products and merchandise	**$ 4,715**	$ 4,463	$ 4,285
Matching crude oil and refined product buy/sell transactions settled in cash:			
E&P	**$ 123**	$ 167	$ 222
RM&T	**12,513**	9,075	6,961
Total buy/sell transactions included in revenues	**$ 12,636**	$ 9,242	$ 7,183

E&P segment revenues increased by $1.490 billion in 2005 from 2004 and by $119 million in 2004 from 2003. The 2005 increase was primarily due to 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. Derivative losses included in E&P segment revenues totaled $5 million in 2005, $169 million in 2004 and $110 million in 2003. Excluded from E&P segment revenues were losses of $386 million in 2005, $99 million in 2004 and $66 million in 2003 related to long-term natural gas sales contracts in the U.K. that are accounted for as derivative instruments. See Item 7A. Quantitative and Qualitative Disclosures about Market Risk on page 53. Matching buy/sell transactions decreased by $44 million in 2005 from 2004 and by $55 million in 2004 from 2003. The 2005 and 2004 decreases were primarily due to decreased crude oil buy/sell volumes, partially offset by higher domestic liquid hydrocarbon prices.

RM&T segment revenues increased by $12.373 billion in 2005 from 2004 and by $9.116 billion in 2004 from 2003. 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. The 2004 increase primarily reflected higher refined product and crude oil prices and increased refined product and crude oil sales volumes. Matching buy/sell transactions increased by $3.438 billion in 2005 from 2004 and by $2.114 billion in 2004 from 2003. The 2005 and 2004 increases were primarily due to increased crude oil prices and volumes and higher refined product prices and volumes.

IG segment revenues increased by $345 million in 2005 from 2004 and decreased by $509 million in 2004 from 2003. The increase in 2005 is a result of higher natural gas prices. The decrease in 2004 is due to a decrease in natural gas marketing activities, partially offset by higher natural gas prices. Derivative gains included in IG segment revenues totaled $13 million in 2005, compared to gains of $17 million in 2004 and $19 million in 2003.

For additional information on segment results, see the discussion on income from operations on page 39.

Income from equity method investments increased by $96 million in 2005 from 2004 and by $141 million in 2004 from 2003. The increase in 2005 is primarily due to higher income from Alba Plant, LLC as a result of higher LPG and condensate production volume and higher income from PTC as a result of higher distillate gross margins. The increase in 2004 resulted from a $124 million loss on the dissolution of MKM Partners L.P. recorded in 2003. Results for 2004 also include increased earnings of other equity method investments, primarily AMPCO.

Cost of revenues increased by $7.107 billion in 2005 from 2004 and by $5.840 billion in 2004 from 2003. The increases are primarily in the RM&T segment and resulted from an increase in acquisition costs for crude oil, an increase in the cost of refined product purchases, an increase in the cost of other refinery charge and blend stocks and higher manufacturing expenses, primarily the result of higher purchased energy and depreciation.

Purchases related to matching buy/sell transactions increased by $3.314 billion in 2005 from 2004 and $1.837 billion in 2004 from 2003, primarily in the RM&T segment. The increases in both years are primarily due to

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increased crude oil prices. Differences between revenues from matching buy/sell transactions and purchases related to matching buy/sell transactions are primarily grade/quality and location differentials.

Selling, general and administrative expenses increased by $133 million in 2005 from 2004 and by $105 million in 2004 from 2003. The increase in 2005 was primarily a result of increased stock-based compensation expense due to the increase in the stock price during the year as well as an increase in equity-based awards. This was partially offset by a decrease as a result of severance and pension plan curtailment charges and start-up costs related to EGHoldings in 2004. The increase in 2004 was primarily due to increased stock-based compensation and higher costs associated with business transformation and outsourcing. Our 2004 results were also impacted by the start-up costs discussed above and the increased cost of complying with governmental regulations.

Other taxes increased by $144 million in 2005 from 2004 and increased $39 million in 2004 from 2003. The increase in 2005 is primarily a result of increased payments of mineral extraction tax and export duty in Russia due to higher sales volumes and crude oil prices.

Net interest and other financial costs decreased by $16 million in 2005 from 2004 and by $25 million in 2004 from 2003. The decrease in 2005 is primarily a result of increased interest income on higher average cash balances and capitalized interest, partially offset by increased interest on potential tax deficiencies and higher foreign exchange losses. The decrease in 2004 is primarily due to an increase in interest income on higher cash balances. Included in net interest and other financing costs are foreign currency losses of $17 million, and gains of $9 million and $13 million for 2005, 2004 and 2003.

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

Provision for income taxes increased by $1.003 billion in 2005 from 2004 and by $143 million in 2004 from 2003, primarily due to $2.797 billion and $388 million increases in income from continuing operations before income taxes.

The effective tax rate for 2005 was 36.2 percent compared to 36.6 percent for both 2004 and 2003. The following is an analysis of the effective tax rate for the periods presented:

	2005	2004	2003
Statutory tax rate	**35.0%**	35.0%	35.0%
Effects of foreign operations	**(0.9)**	1.3	(0.4)
State and local income taxes after federal income tax effects	**2.5**	1.6	2.2
Other federal tax effects	**(0.4)**	(1.3)	(0.2)
Effective tax rate	**36.2%**	36.6%	36.6%

Discontinued operations in 2004 and 2003 primarily relates to our E&P operations in western Canada, which were sold in 2003 for a gain of $278 million, including a tax benefit of $8 million. Also, included in 2003 results is an $8 million adjustment to a tax liability due to United States Steel Corporation.

Cumulative effect of changes in accounting principles 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. The cumulative effect of a change in accounting principle in 2003 was a favorable effect of $4 million, net of taxes of $4 million, representing the adoption of Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations.

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Income from operations for each of the last three years is summarized in the following table:

(In millions)	**2005**	2004	2003
E&P			
Domestic	**$ 1,564**	$ 1,073	$ 1,155
International	**1,424**	623	425
E&P segment income	**2,988**	1,696	1,580
RM&T	**3,013**	1,406	819
IG	**31**	48	(3)
Segment income	**6,032**	3,150	2,396
Items not allocated to segments:			
Administrative expenses	**(367)**	(307)	(227)
Loss on long-term U.K. gas contracts[a]	**(386)**	(99)	(66)
Gain on sale of minority interests in EGHoldings	**23**		
Impairment of certain oil and gas properties[b]		(44)	
Corporate insurance adjustment[c]		(32)	
Gain (loss) on ownership change in MPC		2	(1)
Gain on asset dispositions[d]			106
Loss on dissolution of MKM Partners L.P.[e]			(124)
Income from operations	**$ 5,302**	$ 2,670	$ 2,084

(a) Amounts relate to long-term gas contracts in the U.K. that are accounted for as derivative instruments and recorded at fair value. See Critical Accounting Estimates Fair Value Estimates on page 34 for further discussion.

(b) Amount includes $32 million related to unproved properties and $12 million related to producing properties primarily due to unsuccessful developmental drilling activity in Russia.

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

(d) Amount represents a gain on the disposition of our interest in CLAM Petroleum B.V. and certain fields in the Big Horn Basin of Wyoming and SSA stores in Florida, North Carolina, South Carolina and Georgia.

(e) See Note 13 to the consolidated financial statements for a discussion of the dissolution of MKM Partners L.P.

Average Volumes, Selling Prices and Other Statistics

	2005	2004	2003
Net liquid hydrocarbon sales (mbpd)[(a)(b)]			
United States	**76.4**	81.2	106.5
Equity method investee			4.4
Total United States	**76.4**	81.2	110.9
Europe	**36.3**	39.8	41.5
Africa	**51.7**	32.5	27.1
Other International	**26.6**	15.6	10.0
Equity method investee		1.0	1.2
Total International[(c)]	**114.6**	88.9	79.8
Worldwide continuing operations	**191.0**	170.1	190.7
Discontinued operations			3.1
WORLDWIDE	**191.0**	170.1	193.8
Net natural gas sales (mmcfd)[(b)(d)]			
United States	**577.6**	631.2	731.6
Europe	**262.0**	291.8	285.9
Africa	**92.4**	76.4	65.9
Equity method investee			12.4
Total International	**354.4**	368.2	364.2
Worldwide continuing operations	**932.0**	999.4	1,095.8
Discontinued operations			74.1
WORLDWIDE	**932.0**	999.4	1,169.9
Total sales (mboepd)	**346.3**	336.7	388.8
Average sales prices (excluding derivative gains and losses)			
Liquid hydrocarbons ($ per bbl)[(a)]			
United States	**$ 45.41**	$ 32.76	$ 26.92
Equity method investee			29.45
Total United States	**45.41**	32.76	27.02
Europe	**52.99**	37.16	28.50
Africa	**46.27**	35.11	26.29
Other International	**33.47**	22.65	18.33
Equity method investee		21.10	13.72
Total International	**45.43**	33.68	26.24
Worldwide continuing operations	**45.42**	33.24	26.70
Discontinued operations			28.96
WORLDWIDE	**$ 45.42**	$ 33.24	$ 26.73
Natural gas ($ per mcf)			
United States	**$ 6.42**	$ 4.89	$ 4.53
Europe	**5.70**	4.13	3.35

Africa	**0.25**	0.25	0.25
Equity method investee			3.69
Total International	**4.28**	3.33	2.80
Worldwide continuing operations	**5.61**	4.31	3.95
Discontinued operations			5.43
WORLDWIDE	**$ 5.61**	$ 4.31	$ 4.05
Refined products sales volumes (mbpd)[e]	**1,455**	1,400	1,357
Matching buy/sell volumes included in refined products volumes (mbpd)	**77**	71	64
Refining and wholesale marketing margin (per gallon)[f]	**$ 0.1582**	$ 0.0877	$ 0.0603

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

(b) Amounts represent net sales after royalties, except for the U.K., Ireland and the Netherlands where amounts are before royalties for the applicable periods.

(c) Amounts represent 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) Includes natural gas acquired for injection and subsequent resale of 38.1, 19.3 and 23.4 mmcfd in 2005, 2004 and 2003, 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.

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

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

Domestic E&P income increased by $491 million in 2005 from 2004 following a decrease of $82 million in 2004 from 2003. The increase in 2005 was primarily due to higher natural gas and liquid hydrocarbon prices partially offset by lower sales volumes. The lower volumes in 2005 resulted primarily from weather-related downtime in the Gulf of Mexico and natural declines in field production rates. The decrease in 2004 was due to lower liquid hydrocarbon and natural gas volumes primarily resulting from natural field declines, weather-related downtime in the Gulf of Mexico and the sale of the Yates field in late 2003, partially offset by higher liquid hydrocarbon and natural gas prices. Derivative losses totaled $5 million in 2005, compared to $118 million in 2004 and $91 million in 2003.

Our cost of storm-related repairs as a result of 2005 hurricane activity in the Gulf of Mexico was not significant. Our Gulf of Mexico production has 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.

Our domestic average realized liquid hydrocarbons price excluding derivative activity was $45.41 per barrel (bbl) in 2005, compared to $32.76 per bbl in 2004 and $27.02 per bbl in 2003. Domestic average natural gas prices were $6.42 per thousand cubic feet (mcf) excluding derivative activity in 2005, compared with $4.89 per mcf in 2004 and $4.53 per mcf in 2003.

Domestic net liquid hydrocarbon sales volumes decreased to 76 thousand barrels per day (mbpd) in 2005, down 6 percent from 2004 primarily as a result of storm-related downtime in the Gulf of Mexico and natural field declines in the Permian Basin. Domestic net natural gas sales volumes averaged 578 million cubic feet per day (mmcfd), down 8 percent from 2004, primarily as a result of lower production in the Permian Basin and Camden Hills in the Gulf of Mexico due to natural field declines and downtime associated with Hurricane Ivan. Domestic net liquid hydrocarbon sales volumes decreased 27 percent to 81 mbpd in 2004 from 2003 as a result of natural declines mainly in the Gulf of Mexico, hurricane damage to the Petronius platform and the sale of the Yates field in November 2003. Domestic net natural gas sales volumes decreased 14 percent to 631 mmcfd in 2004 from 2003 as a result of hurricane damage to the Petronius platform and natural declines in the Permian Basin and the Gulf of Mexico.

International E&P income increased by $801 million in 2005 from 2004 and by $198 million in 2004 from 2003. The increase in 2005 was primarily the result of higher product prices and liquid hydrocarbon sales volumes, partially offset by higher production taxes in Russia, dry well expenses and lower natural gas sales volumes. The increase in 2004 was primarily due to higher liquid hydrocarbon and natural gas prices and volumes partially offset by higher derivative losses. Derivative losses totaled $386 million in 2005, compared to $51 million in 2004 and $19 million in 2003.

Our international average realized liquid hydrocarbon price excluding derivative activity was $45.43 per bbl in 2005, compared with $33.68 per bbl in 2004 and $26.24 per bbl in 2003. International average gas prices were $4.28 per mcf excluding derivative activity in 2005, compared with $3.33 per mcf in 2004 and $2.80 per mcf in 2003.

International net liquid hydrocarbon sales volumes increased to 115 mbpd in 2005, up 29 percent from 2004, as a result of increased production in Equatorial Guinea and Russia. International net natural gas sales volumes averaged 354 mmcfd in 2005, down 4 percent from 2004, primarily as a result of reduced U.K. spot gas sales. International net liquid hydrocarbon sales volumes increased 11 percent to 89 mbpd in 2004 from 2003 primarily due to increased production in Equatorial Guinea and a full year of production from Khanty Mansiysk Oil Corporation (KMOC) which was acquired in 2003. International net natural gas sales volumes averaged 368 mmcfd, up 1 percent from 2003 due to increased production from the condensate expansion project in Equatorial Guinea, offset by the disposition in 2003 of our interest in CLAM.

RM&T segment income increased by $1.607 billion in 2005 from 2004 and by $587 million in 2004 from 2003. The increases were primarily due to higher refining and wholesale marketing margins. The refining and wholesale marketing margin in 2005 averaged 15.8 cents per gallon, versus a 2004 level of 8.8 cents and a 2003 level of 6.0 cents. Margins improved initially in 2005 due to wider sweet/sour crude differentials, and more recently, due to the temporary impact that Hurricanes Katrina and Rita had on refined product margins and concerns about the adequacy of distillate supplies heading into winter. Margins improved initially in 2004 due to the market s concerns about refiners ability to supply the new Tier II low sulfur gasolines which were required effective January 1, 2004. We also benefited from wider sweet/sour crude differentials in 2004. We averaged 973,000 barrels of crude oil throughput per day in 2005, or 102 percent of average system capacity. We averaged 939,000 barrels of crude oil throughput per day in 2004 and 917,000 in 2003, representing 99 percent and 98 percent of average system capacity for those years.

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The portion of derivative losses included in the refining and wholesale marketing margin were $238 million in 2005 compared to $272 million in 2004 and $158 million in 2003. Generally, losses on derivatives included in the refining and wholesale marketing margin are offset by gains on the underlying physical transactions. These derivative losses were primarily incurred to mitigate the price risk of certain crude oil and other feedstock purchases, to protect carrying values of excess inventories and to protect crack spread values.

IG segment income decreased by $17 million in 2005 from 2004, following an increase of $51 million in 2004 from 2003. The decrease in 2005 was primarily due to increased income taxes for AMPCO as a result of the expiration of a tax holiday. The increase in 2004 was primarily due to increased earnings from our investment in AMPCO and higher income from our Alaska LNG operations, partially offset by costs associated with ongoing development of certain integrated gas projects and lower margins from gas marketing activities, including recognized changes in the fair value of derivatives used to support those activities. Additionally, the 2003 results included an impairment charge of $22 million on an equity method investment and a loss of $17 million on the termination of two operating leases for tankers used in our Alaska LNG operations. The AMPCO methanol plant in Equatorial Guinea operated at a 98 percent on-stream factor in 2005 and a 95 percent on-stream factor in 2004, and posted index prices for methanol remained strong.

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

Financial Condition

Both our acquisition of the minority interest in MPC and our re-entry to Libya discussed in Note 5 to the consolidated financial statements had a significant impact on our December 31, 2005 consolidated balance sheet. The MPC transaction closed June 30, 2005 and was accounted for under the purchase method of accounting. As a result, we established a new accounting basis for the tangible and identifiable intangible net assets of MPC to the extent of the 38 percent of MPC not previously owned by us, based on the estimated fair values of those net assets as of June 30, 2005. On December 29, 2005, we entered into an agreement with the National Oil Corporation of Libya to return to our oil and natural gas exploration and production operations in the Waha concessions in Libya. This transaction was also accounted for under the purchase method of accounting.

Changes in the consolidated balance sheets from 2004 to 2005 were significantly impacted by the acquisitions noted above. For additional information on the effects of both of these transactions on our financial condition, see Note 5 to the consolidated financial statements. Other significant changes in the consolidated balance sheets are noted below.

Net property, plant and equipment increased $3.201 billion from year-end 2004 due to the acquisitions noted above as well as the projects in Equatorial Guinea and the Alvheim development offshore Norway affecting International E&P, the Detroit refinery expansion affecting RM&T and the EG LNG plant affecting IG. Net property, plant and equipment for each of the last two years is summarized in the following table:

(In millions)	**2005**	2004
E&P		
Domestic	**$ 2,799**	$ 2,644
International	**4,737**	3,530
Total E&P	**7,536**	6,174
RM&T	**6,113**	4,842
IG	**1,157**	621
Corporate	**205**	173
Total	**$ 15,011**	$ 11,810

Asset retirement obligations increased $234 million from year-end 2004 primarily due to upward revisions of previous estimates primarily in the U.K. and Ireland, a change in the Gabon production sharing contract that created a retirement obligation and adoption of FIN No. 47 related to conditional asset retirement obligations on December 31, 2005.

Cash Flows

Net cash provided from operating activities (for continuing operations) totaled $4.738 billion in 2005, compared with $3.766 billion in 2004 and $2.765 billion in 2003. 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. The 2004 increase was primarily the result of working capital changes.

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

(In millions)	**2005**	2004	2003
E&P			
Domestic	**$ 637**	$ 402	$ 344
International	**823**	542	629
Total E&P	**1,460**	944	973
RM&T	**841**	794	789
IG	**572**	490	131
Corporate	**17**	19	16
Total	**$ 2,890**	$ 2,247	$ 1,909

Capital expenditures in 2005 totaled $2.890 billion compared with $2.247 billion in 2004 and $1.909 billion in 2003. The $643 million increase in 2005 mainly resulted from increased spending in the E&P segments related to the Alvheim development offshore Norway and in the IG segment associated with the EG LNG plant. The increase of $338 million in 2004 from 2003 mainly resulted from increased spending in the IG segment associated with the EG LNG plant.

Acquisitions included cash payments of $506 million in 2005 for the acquisition of Ashland s 38 percent ownership in MPC and $252 million in 2003 for the acquisition of KMOC. For further discussion of acquisitions, see Note 5 to the consolidated financial statements.

Cash from disposal of assets was $131 million in 2005, compared with $76 million in 2004 and $1.256 billion in 2003 which includes the disposal of discontinued operations. In 2005 and 2004, proceeds were primarily from the sale of various domestic producing properties and SSA stores. In 2003, proceeds were primarily from the disposition of our E&P properties in western Canada, the Yates field and gathering system, various SSA stores and other interests and producing properties.

Net cash used in financing activities totaled $2.345 billion in 2005, compared with net cash provided of $527 million in 2004 and net cash used of $888 million in 2003. The change from 2004 to 2005 was primarily related to the repayment of $1.920 billion of debt assumed as a part of the Acquisition in 2005 and to the issuance of 34,500,000 shares of common stock on March 31, 2004, resulting in net proceeds of $1.004 billion in 2004. The change also included an increase in dividends paid and $272 million of distributions to the minority shareholder of MPC prior to the Acquisition, net of an increase in contributions from the minority shareholders of EGHoldings. The increase in 2004 was due to the net proceeds from the common stock issuance discussed above as well as the suspension of distributions to the minority shareholder of MPC in 2004. This was partially offset by an increase in dividends paid to stockholders.

Derivative Instruments

See Quantitative and Qualitative Disclosures about Market Risk on page 53, for a discussion of derivative instruments and associated market risk.

Dividends to Stockholders

Dividends of $1.22 per common share or $436 million were paid during 2005. On January 29, 2006, our Board of Directors declared a dividend of 33 cents per share on our common stock, payable March 10, 2006, to stockholders of record at the close of business on February 16, 2006.

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 for the years 2006, 2007 and 2008, and any amounts that may ultimately be paid in connection with contingencies.

We have a committed $1.5 billion five-year revolving credit facility that terminates in May 2009. At December 31, 2005, there were no borrowings against this facility. At December 31, 2005, we had no commercial paper outstanding under our U.S. commercial paper program that is backed by the five-year revolving credit facility.

MPC has a committed $500 million five-year revolving credit facility with third-party financial institutions that terminates in May 2009. At December 31, 2005, there were no borrowings against this facility.

As a condition of the closing agreements for the Acquisition, we are required to maintain MPC on a stand-alone basis financially for a two-year period. 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. MPC may only use its revolving credit facility for short-term working capital requirements in a manner consistent with past practices. There are no restrictions against MPC making intercompany loans or declaring dividends to its parent. We believe these facilities and cash provided from MPC s operations will be adequate to meet its liquidity requirements.

As of December 31, 2005, 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. On June 30, 2005, we issued $955 million of common stock to Ashland shareholders through a separate registration statement filed with the Securities and Exchange Commission which was declared effective May 20, 2005.

Our cash-adjusted debt-to-capital ratio (total-debt-minus-cash to total-debt-plus-equity-minus-cash) was 11 percent at December 31, 2005, compared to 8 percent at year-end 2004 as shown below. This includes $543 million of debt that is serviced by United States Steel. We continually monitor our spending levels, market conditions and related interest rates to maintain what we perceive to be reasonable debt levels.

(Dollars in millions)	**December 31 2005**	December 31 2004
Long-term debt due within one year	**$ 315**	$ 16
Long-term debt	**3,698**	4,057
Total debt	**$ 4,013**	$ 4,073
Cash	**$ 2,617**	$ 3,369
Equity	**$ 11,705**	$ 8,111
Calculation:		
Total debt	**$ 4,013**	$ 4,073
Minus cash	**2,617**	3,369
Total debt minus cash	**1,396**	704
Total debt	**4,013**	4,073
Plus equity	**11,705**	8,111
Minus cash	**2,617**	3,369
Total debt plus equity minus cash	**$ 13,101**	$ 8,815
Cash-adjusted debt-to-capital ratio	**11%**	8%

On December 29, 2005, in conjunction with our partners in the former Oasis Group, we entered into an agreement with the National Oil Corporation of Libya to return to our oil and natural gas exploration and production operations in the Waha concessions in Libya. The re-entry terms include a 25-year extension of the concessions to 2030 through

2034 and a payment of $520 million from us, which was made in January 2006. An additional payment estimated to be approximately $212 million is payable by us within one year of the agreement date.

On January 29, 2006, our Board of Directors authorized the repurchase of up to $2 billion of our common stock over a period of two years. Such purchases will be made during this period as our financial condition and market conditions warrant. Any purchases under the program may be in either open market transactions, including block purchases, or in privately negotiated transactions. The repurchase program does not include specific price targets, and is subject to termination prior to completion. We will use cash on hand, cash generated from operations, or cash from available borrowings to acquire shares. Shares of stock repurchased under the program will be held as treasury shares.

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The table below provides aggregated information on our obligations to make future payments under existing contracts as of December 31, 2005:

Summary of Contractual Cash Obligations

(In millions)	Total	2006	2007-2008	2009-2010	Later Years
Long-term debt (excludes interest)[a][b]	$ 3,874	$ 302	$ 850	$	$ 2,722
Sale-leaseback financing (includes imputed interest)[a]	85	11	30	22	22
Capital lease obligations[a]	156	16	33	33	74
Operating lease obligations[a]	517	100	102	68	247
Operating lease obligations under sublease[a]	43	12	11	10	10
Purchase obligations:					
Crude oil, refinery feedstock and refined products contracts[c]	10,771	10,660	111		
Transportation and related contracts	1,027	209	271	150	397
Contracts to acquire property, plant and equipment	668	543	123	1	1
LNG facility operating costs[d]	192	13	25	25	129
Service and materials contracts[e]	185	71	45	38	31
Unconditional purchase obligations[f]	69	7	14	14	34
Commitments for oil and gas exploration (non-capital) [g]	20	20			
Total purchase obligations	12,932	11,523	589	228	592
Other long-term liabilities reported in the consolidated balance sheet:					
Employee benefit obligations[h]	2,321	201	385	396	1,339
Total contractual cash obligations[i]	**$ 19,928**	**$ 12,165**	**$ 2,000**	**$ 757**	**$ 5,006**

[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 $255 million for 2006, $432 million for 2007-2008, $385 million for 2009-2010 and $1.658 billion for the remaining years for a total of $2.730 billion.

[c] The majority of contractual obligations to purchase crude oil, refinery feedstock and refined products as of December 31, 2005 relate to contracts to be satisfied within the first 180 days of 2006.

[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 LNG re-gasification 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 28 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 employee benefit obligations consisting of pensions and other postretirement benefits including medical and life insurance. We have estimated projected funding requirements through 2014.

(i) Includes $625 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 47.

Contractual cash obligations for which the ultimate settlement amounts are not fixed and determinable have been excluded from the above table. These include derivative contracts that are sensitive to future changes in commodity prices and other factors.

Note 23 to the consolidated financial statements includes detailed information for the three years ended December 31, 2005, on the funded status for our pension plans as of December 31, 2005 and 2004. Under prescribed regulatory minimum funding requirements, we have satisfied the minimum funding obligations related to the pension plans and therefore no contributions are required from us. However, we plan to make discretionary cash contributions of between $155 million and $345 million in 2006.

Our opinions concerning liquidity and our ability to avail ourselves in the future of the financing options mentioned in the above forward-looking statements are based on currently available information. If this information proves to be inaccurate, future availability of financing may be adversely affected. Factors that affect the availability of financing include our performance (as measured by various factors including cash provided from operating activities), the state of worldwide debt and equity markets, investor perceptions and expectations of past and future performance, the global financial climate, and, in particular, with respect to borrowings, the levels of our outstanding debt and credit ratings by rating agencies.

The 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 thereto, and other operating and economic considerations.

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 certain lease contracts. These arrangements are described in Note 28 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 28 to the consolidated financial statements.

Nonrecourse Indebtedness of Investees

Certain of our investees have incurred indebtedness that we do not support through guarantees or otherwise. If we were obligated to share in this debt on a pro rata ownership basis, our share would have been approximately $308 million as of December 31, 2005. Of this amount, $183 million relates to PTC. If any of these investees default, we have no obligation to support the debt. Our partner in PTC has guaranteed $125 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, 2005, we have identified the following obligations totaling $597 million that have been assumed by United States Steel:

$428 million of industrial revenue bonds related to environmental improvement projects for current and former United States Steel facilities, with maturities ranging from 2009 through 2033. Accrued interest payable on these bonds was $9 million at December 31, 2005.

$66 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, 2005.

$49 million of obligations under a lease for equipment at United States Steel s Clairton cokemaking facility, with a term extending to 2012. There was no accrued interest payable on this financing at December 31, 2005.

$45 million of operating lease obligations, of which $37 million 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 $597 million, obligations of $552 million and corresponding receivables from United States Steel were recorded on our consolidated balance sheet as of December 31, 2005 (current portion $20 million; long-term portion $532 million). The remaining $45 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, 2005:

Summary of Contractual Cash Obligations Assumed by United States Steel

(In millions)	**Total**	**2006**	**2007-2008**	**2009-2010**	**Later Years**
Long-term debt[a]	$ 428	$	$	$	$ 428
Sale-leaseback financing (includes imputed interest)	85	11	30	22	22
Capital lease obligations	67	10	19	19	19
Operating lease obligations	8	5	3		
Operating lease obligations under sublease	37	5	11	10	11
Total contractual obligations assumed by United States Steel	**$ 625**	**$ 31**	**$ 63**	**$ 51**	**$ 480**

[a] We anticipate cash payments for interest of $24 million for 2006, $47 million for 2007-2008, $47 million for 2009-2010 and $272 million for the later years to be assumed by United States Steel.

Each of Marathon and United States Steel, as members of the same consolidated tax reporting group during taxable periods ended on or before December 31, 2001, is jointly and severally liable for the federal income tax liability of the entire consolidated tax reporting group for those periods. 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. The agreement includes indemnification provisions to address the possibility that the taxing authorities may seek to collect a tax liability from one party where the tax sharing agreement allocates that liability to the other party. In 2005, in accordance with the terms of the tax sharing agreement, we paid $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 1997.

United States Steel reported in its Form 10-K for the year ended December 31, 2005, 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 EG. 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 less than two percent of our total sales revenue for 2005, 2004 and 2003. PTC is the largest travel center network in the United States and operates approximately 260 travel centers nationwide. We also sell refined petroleum products consisting mainly of petrochemicals, base lube oils, and asphalt to Ashland which owned a 38 percent interest in MPC prior to the Acquisition. Our sales to Ashland accounted for less than one percent of our total sales revenue for 2005, 2004 and 2003. We believe that these transactions were conducted under terms comparable to those with unrelated parties.

Marathon holds a 60 percent economic interest, GEPetrol holds a 25 percent economic interest, Mitsui holds an 8.5 percent economic interest and Marubeni holds a 6.5 percent economic interest in EGHoldings. As of December 31, 2005, total expenditures of $1.116 billion, including $1.066 billion of capital expenditures, related to the LNG project have been incurred. Cash of $57 million held in escrow to fund future contributions from GEPetrol is classified as restricted cash and is included in investments and long-term receivables. Payables to related parties include $57 million payable to GEPetrol.

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 recovered in the prices of our products and services, 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)	**2005**	2004	2003
Capital	**$ 390**	$ 433	$ 331
Compliance			
Operating & maintenance	**250**	215	243
Remediation[b]	**25**	32	44
Total	**$ 665**	$ 680	$ 618

[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 13 percent of total capital expenditures in 2005, 19 percent in 2004 and 17 percent in 2003.

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 $218 million or 7 percent of capital expenditures in 2006. Predictions beyond 2006 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 $147 million in 2007; however, actual expenditures may vary as the number and scope of environmental projects are revised as a result of improved technology or changes in regulatory requirements and could increase if additional projects are identified or additional requirements are imposed.

Of particular significance to our refining operations are EPA regulations that require reduced sulfur levels starting in 2004 for gasoline and in 2006 for diesel fuel. Our combined capital costs to achieve compliance with these rules are expected to approximate $900 million over the period between 2002 and 2006, which includes costs that could be incurred as part of other refinery upgrade projects. Costs incurred through December 31, 2005, were approximately $825 million, with the remainder expected to be incurred in 2006. This is a forward-looking statement. Some factors (among others) that could potentially affect gasoline and diesel fuel compliance costs include completion of construction and start-up activities.

During 2001, MPC entered into a New Source Review consent decree and settlement of alleged CAA and other violations with the EPA covering all of MPC s refineries. The settlement committed MPC to specific control technologies and implementation schedules for environmental expenditures and improvements to MPC s refineries over approximately an eight-year period. The total one-time expenditures for these environmental projects are approximately $420 million over the eight-year period, with about $265 million incurred through December 31, 2005. The impact of the settlement on ongoing operating expenses is expected to be immaterial. In addition, MPC has nearly completed certain agreed upon supplemental environmental projects as part of this settlement of an enforcement action for alleged CAA violations, at a cost of $9 million. We believe this settlement will provide MPC with increased permitting and operating flexibility while achieving significant emission reductions. In 2005, MPC entered into two amendments of the consent decree which captured all revisions to the decree agreed to with the EPA since 2001. The revisions related to use of additives and control technologies along with schedule adjustments and other changes. The costs of these consent decree revisions are immaterial and are included in the cost estimates provided in this paragraph.

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 $3.4 billion for 2006, which includes budgeted capital expenditures of $3.2 billion. This represents a 13 percent increase over 2005 actual spending. The primary focus of the 2006 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 capital spending of $1.357 billion primarily in the United States, Norway, Russia, Equatorial Guinea and Ireland. The worldwide exploration budget of $588 million includes plans to drill 19 significant exploration wells. Other activities will focus on projects primarily within or adjacent to our onshore producing properties in the United States. The budget includes $886 million for RM&T, primarily for refining investments targeting value-added projects primarily aimed at de-bottlenecking various refining components to increase throughput capacity, as well as investments necessary to meet revised EPA National Ambient Air Quality Standards, best achievable control technology and Tier II Clean Fuels regulations. Also included in the budget for RM&T is planned spending for the FEED work being undertaken for the potential 180,000 bpd Garyville, Louisiana refinery expansion project. The IG budget of $341 million is primarily for the ongoing construction of the EG LNG plant. The remaining $210 million balance is designated for capitalized interest and corporate activities. This budget does not include the 2006 cash payments related to our re-entry to Libya, estimated to be $732 million.

Exploration and Production

Our eight discoveries in 2005 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 in:

- Offshore Angola, where development options for the northeast area of Block 31, which includes the Plutao, Saturno, Marte and Venus discoveries, are currently being evaluated. Also on Block 31 during 2005, the announcement of five discoveries, Ceres, Palas, Juno, Astraea and Hebe, in the southeastern part of the block reinforce the likelihood of a second development area. The Urano well was started in December 2005 and drilling is in progress. We own a 10 percent interest in Block 31. We have secured rig capacity for and plan to participate in five exploration wells during 2006.

- On Angola Block 32, in which we own a 30 percent interest, three discoveries were announced, Gindungo, Canela and Gengibre. We also participated in a well on the Cola prospect that encountered hydrocarbons, but additional drilling will be required to determine commerciality. Finally, we announced a successful appraisal of the Gengibre discovery and the Mostarda well has reached total depth. These results will be announced following government approval. We have secured rig capacity for and plan to participate in six exploration wells during 2006.

- 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 facility under construction on Bioko Island. We own a 63 percent interest in the Alba Block and serve as operator.

Norway, where we acquired four new Norwegian exploration licenses (three operated) in the December 2004 APA License Round. We now own interests in 16 licenses in the Norwegian sector of the North Sea and plan to drill one to two exploration wells during 2006.

Gulf of Mexico, where we plan to participate in one to four wells during 2006.

During 2005, 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 have extended the licenses for an additional 25 years. In 2006 we will do more detailed analysis of work to be completed to maximize the potential of this major asset which currently produces 350,000 bpd gross and we expect to contribute 40,000 to 45,000 bpd net to Marathon during 2006. We own a 16.33 percent interest in the approximately 13 million acre Waha concessions.

Norway, where our Alvheim development will consist of a floating production, storage and offloading (FPSO) vessel with subsea infrastructure for five drill centers and associated flow lines. At year-end 2005 the project was 43 percent complete with production expected to start during the first quarter 2007. The Alvheim development includes the Kneler, Boa and Kameleon fields in which we own a 65 percent interest and serve as operator. A development plan for the nearby Vilje discovery, in which we own a 47 percent interest, was approved by the Norwegian Government in 2005. The combined Alvheim/ Vilje developments are expected to ramp up production in the first quarter of 2007 to more than 50,000 net boepd. Also, results for the Volund well (formerly Hamsun) are being analyzed and development scenarios are being examined, including a possible tie-back to the Alvheim development. We own a 65 percent interest in Volund and serve as operator.

Gulf of Mexico, where the Neptune development was sanctioned during 2005 and which is on track for first production in late 2007 or early 2008.

Equatorial Guinea, where we completed our LPG expansion project and ramped up liquids production to approximately 86,000 gross bpd (49,000 bpd net to Marathon) by the end of 2005. We continue to exceed our initial liquids production projection, as gross production available for sale in January 2006 was approximately 90,000 bpd (51,000 bpd net to Marathon).

Russia, where our successful drilling program in East Kamennoye took our production to greater than 30,000 net bpd at year end, more than double the production level when we acquired the assets in 2003.

In January 2006, we began to experience pipeline operational problems related to the increasing water production associated with the natural gas production from the Camden Hills field in the Gulf of Mexico. If these issues cannot be resolved, we may need to impair some or all of the carrying value of the field and the associated Canyon Express pipeline. At December 31, 2005, the combined carrying value of those assets approximated $20 million.

The above discussion includes forward-looking statements with respect to the timing and levels of our worldwide liquid hydrocarbon and natural gas production, future exploration and drilling activity, possible development of Blocks 31 and 32 offshore Angola, the Neptune development, the Alvheim/ Vilje development and estimated levels of production in Libya. Some factors that could potentially affect this forward-looking information include pricing, supply and demand for petroleum products, amount of capital available for exploration and development, occurrence of acquisitions/dispositions of oil and gas properties, regulatory constraints, timing of commencing production from new wells, drilling rig availability, unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response thereto, and other geological, operating and economic considerations. The estimated levels of production in Libya and possible development of Blocks 31 and 32 offshore Angola could further be affected by presently known data concerning size and character of reservoirs, economic recoverability, future drilling success and production experience. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Refining, Marketing and Transportation

Throughout 2005, 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. The record refinery throughput performance was achieved even though the Garyville, Louisiana and Texas City, Texas refineries were shut down briefly due to Hurricanes Katrina and Rita. Based on our current plans, we expect our 2006 average crude oil throughput to exceed that achieved in 2005.

The Detroit refinery expansion was completed in the fourth quarter of 2005. This project increased the refinery s crude processing capacity from 74,000 bpd to 100,000 bpd as well as enabled the refinery to produce new clean fuels and further control regulated air emissions. The refinery ramped up to full capacity of 100,000 bpd in mid-November.

We plan to evaluate a 180,000 bpd expansion of the 245,000 bpd Garyville, Louisiana refinery. The initial phase of the potential expansion includes FEED work which began in December 2005 and could lead to the start of construction in 2007. The project, currently estimated to cost approximately $2.2 billion, could be completed as early as the fourth quarter of 2009. The final investment decision is subject to completion of the FEED work and the receipt of applicable permits.

The above discussion includes forward-looking statements with respect to projections of crude oil throughput, the Garyville, Louisiana refinery expansion project, and other related businesses. Some factors that could affect crude oil throughput include planned and unplanned refinery maintenance projects, the level of refining margins, and other operating considerations. The Garyville refinery expansion project may be affected by the results of the FEED work, necessary regulatory approvals, crude oil supply and transportation logistics, the receipt of applicable permits, continued favorable investment climate, as well as availability of materials and labor, unforeseen hazards such as weather conditions, and other risks customarily associated with construction projects once construction begins. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Integrated Gas

Construction of the EG LNG plant is ahead of schedule with shipment of first cargoes of LNG expected in the third quarter of 2007. This project is expected to be one of the lowest cost LNG operations in the Atlantic basin with an all-in LNG operating, capital and feedstock cost of approximately $1 per million British thermal units (mmbtu) at the loading flange of the LNG plant. Efforts are underway to acquire additional natural gas supply and expand the utilization of this LNG facility above and beyond the contract to supply 3.4 million metric tons per year to BG Gas Marketing Ltd. for 17 years. We also are seeking additional natural gas supplies in the area to expand the capacity and life of this plant and that could lead to the development of a second LNG train.

Under the five-year BP supply agreement, BP will supply us with 58 billion cubic feet (bcf) of natural gas per year, as LNG. We will take delivery of the LNG at the Elba Island terminal where we hold rights to deliver and sell up to 58 bcf of natural gas per year, with pricing linked to the Henry Hub index. This supply agreement enables us to fully utilize our capacity rights at Elba Island during the period of this agreement, while affording us the flexibility to access this capacity to commercialize other stranded natural gas resources beyond the term of the BP contract. The agreement commenced in 2005.

In 2006, we plan to continue exploring and investing in gas technology research, including GTL technology, which was successfully applied in the Catoosa GTL demonstration plant in 2004. In addition to GTL, we are continuing to explore gas technologies, including methanol to power, gas to fuels and compressed natural gas technologies.

The above discussion contains forward-looking statements with respect to a LNG project and possible expansion thereof. Factors that could affect the LNG project and related facilities include unforeseen problems arising from construction, inability or delay in obtaining necessary government and third-party approvals, unanticipated changes in market demand or supply, environmental issues, availability or construction of sufficient LNG vessels, and unforeseen hazards such as weather conditions. In addition to these factors, other factors that could affect the possible expansion of the LNG project 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.

Corporate

Higher foreign income taxes are expected to result from our Libyan operations, where the effective tax rate is in excess of 90 percent, and an increase in the U.K. supplemental corporation tax rate from 10 percent to 20 percent effective January 1, 2006. Also increasing our overall effective tax rate are the incremental taxes associated with the expected repatriation of foreign earnings to the U.S.

Since 2003, the variable component of our stock-based compensation awards has had a significant impact on our income from operations. We recognize stock-based compensation expense based on the difference between the market price and the grant price of these variable awards each reporting period until settlement. During 2005, we experienced a 66 percent increase in the market price of our common stock. As a result, we recognized $69 million in stock-based compensation expense compared to $30 million for 2004. Due to exercises of these awards during 2005, the number of outstanding variable awards decreased approximately 74 percent. We expect that this change will reduce the impact these variable awards will have on stock-based compensation expense in 2006.

Accounting Standards Not Yet Adopted

In December 2004, the FASB issued SFAS No. 123(R) 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 will be 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 will be remeasured each reporting period. In 2003, we adopted the fair value method for grants made, modified or settled on or after January 1, 2003. Accordingly, we do not expect the adoption of SFAS No. 123(R) to have a material effect on our consolidated results of operations, financial position or cash flows. The statement provided for an effective date of July 1, 2005, for us. However, in April 2005, the Securities and Exchange Commission adopted a rule that, for us, defers the effective date until January 1, 2006. We adopted the provisions of this statement January 1, 2006.

In November 2004, the FASB issued 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. We are required to implement this statement in the first quarter of 2006. We do not expect the adoption of SFAS No. 151 to have a material effect on our consolidated results of operations, financial position or cash flows.

In May 2005, the FASB issued SFAS No. 154, Accounting Changes and Error Corrections. 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. SFAS No. 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005.

In September 2005, the FASB ratified the consensus reached by the Emerging Issues Task Force regarding Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty. The issue defines when a purchase and a sale of inventory with the same party that operates in the same line of business is recorded at fair value or considered a single nonmonetary transaction subject to the fair value exception of APB Opinion No. 29. 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. In general, two or more transactions with the same party are treated as one if they are entered into in contemplation of each other. The rules apply to new arrangements entered into in reporting periods beginning after March 15, 2006. We are currently studying the provisions of this consensus to determine the impact on our consolidated financial statements.

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 FASB s interim 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. SFAS No. 155 is effective for all financial instruments acquired or issued after the beginning of an entity s first fiscal year that begins after September 15, 2006. We are currently studying the provisions of this Statement to determine the impact on our consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk
Management Opinion Concerning Derivative Instruments

Management has authorized the use of futures, forwards, swaps and 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 purchases of ethanol.

Our strategy has generally 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 market risk whereby cash settlement of commodity-based derivatives will be based on market prices.

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

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,
  - associated with anticipated natural gas purchases for refinery use,
  - associated with freight on crude oil, feedstocks and refined product deliveries, and
  - on fixed price contracts for ethanol purchases;
- to protect the value of excess refined product, crude oil and LPG 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.

Our IG segment is exposed to market risk associated with the purchase and subsequent resale of natural gas. We use commodity derivative instruments to mitigate the price risk on purchased volumes and anticipated sales volumes. We use financial derivative instruments to manage foreign currency exchange rate exposure on foreign currency denominated capital expenditures.

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

We believe that 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 use of these instruments will not have a material adverse effect on 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, 2005 and December 31, 2004, are provided in the following table:[a]

(In millions)

	Incremental Decrease in IFO Assuming a Hypothetical Price Change of [a]			
	2005		2004	
Derivative Commodity Instruments[b][c]	**10%**	**25%**	10%	25%
Crude oil[d]	**$ 11**(e)	**$ 25**(e)	$ 1(e)	$
Natural gas[d]	**78**(e)	**195**(e)	36(e)	91(e)
Refined products[d]	**6**(e)	**15**(e)	3(f)	7(f)

[a] We remain at risk for future changes in the market value of derivative instruments; however, such risk should be mitigated by price changes in the underlying hedged item. Effects of these offsets are not reported in the sensitivity analyses. Amounts assume hypothetical 10 percent and 25 percent changes in closing commodity prices, excluding basis swaps, for each open contract position at December 31, 2005 and 2004. The hypothetical price changes of 10 percent and 25 percent would result in incremental decreases in income from operations of $90 million and $225 million for 2005 and $48 million and $119 million for 2004 related to long-term natural gas contracts in the United Kingdom that are accounted for as derivative instruments and these amounts are included above in the impact for natural gas. 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, 2005, would cause future IFO effects to differ from those presented in the table.

[b] Net open contracts for the combined E&P and IG segments varied throughout 2005, from a low of 1,243 contracts at March 10 to a high of 2,192 contracts at January 20, and averaged 1,654 for the year. The number of net open contracts for the RM&T segment varied throughout 2005, from a low of 3,621 contracts at December 19 to a high of 28,079 contracts at March 21, and averaged 18,401 for the year. The derivative commodity instruments used and hedging 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 is based on the largest incremental decrease in IFO when applied to the derivative commodity instruments used to hedge that commodity.

[e] Price increase.

(f) Price decrease.

E&P Segment

Derivative losses included in the E&P segment were $5 million in 2005 compared to $169 million in 2004 and $110 million in 2003. Additionally, losses from discontinued cash flow hedges of $3 million are included in 2004 segment results, compared to losses of $8 million in 2003. The discontinued cash flow hedge amounts were reclassified from accumulated other comprehensive income or loss as it was no longer probable that the original forecasted transactions would occur.

Excluded from the E&P segment results were losses of $386 million in 2005, $99 million in 2004 and $66 million in 2003 on long-term gas contracts in the U.K. that are accounted for as derivative instruments. For additional information on U.K. gas contracts, see Fair Value Estimates on page 34.

During 2005, we have remained 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. In 2003, we reduced our exposure to market prices of commodities on 25 percent of crude oil production and 22 percent of natural gas production.

At December 31, 2005, we had no open derivative contracts related to our oil and gas production and therefore remain exposed to market prices of commodities. 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 derivative instruments to achieve minimum price levels on some portion of our production to support capital or acquisition funding requirements.

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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 income all changes in the fair value of derivatives used in our RM&T operations. Derivative gains or losses included in RM&T segment income for each of the last three years are summarized in the following table:

Strategy *(In millions)*	**2005**	2004	2003
Mitigate price risk	**$ (57)**	$ (106)	$ (112)
Protect carrying values of excess inventories	**(118)**	(98)	(57)
Protect margin on fixed price sales	**18**	8	5
Protect crack spread values	**(81)**	(76)	6
Subtotal non-trading activities	**(238)**	(272)	(158)
Trading activities	**(87)**	8	(4)
Total net derivative losses	**$ (325)**	$ (264)	$ (162)

Derivatives used in non-trading activities have an underlying physical commodity transaction. Derivative losses occur when market prices increase, and generally are offset by gains on the underlying physical commodity transactions. Conversely, derivative gains occur when market prices decrease, and generally are offset by losses on the underlying physical commodity transactions.

In 2005, we realized an $87 million loss on derivative instruments associated with trading activities primarily as a result of unanticipated changes in crude oil and refined product prices.

IG Segment

We have used derivative instruments to convert the fixed price of a long-term gas sales contract to market prices. The underlying physical contract is for a specified annual quantity of gas and matures in 2008. Similarly, we will use derivative instruments to convert shorter term (typically less than a year) fixed price contracts to market prices in our ongoing purchase for resale activity; and to hedge purchased gas injected into storage for subsequent resale. Derivative gains included in IG segment income were $12 million in 2005, $17 million in 2004 and $19 million in 2003. Trading activity in the IG segment resulted in losses of $1 million in 2005, $2 million in 2004 and $7 million in 2003 which have been included in the aforementioned amounts.

Other Commodity Risk

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 (OTC) 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.

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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, 2005		December 31, 2004	
	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	**$ 268**	**$**	$ 266	$
Interest rate swap agreements[(e)]	**$ (30)**	**$ 14**	$ (10)	$ 14
Long-term debt[(d)(e)]	**$ (4,354)**	**$ (152)**	$ (4,480)	$ (164)

(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 Note 17 and 18 to the consolidated financial statements for carrying value of 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, 2005 and 2004. For interest rate swap agreements, this assumes a 10 percent decrease in the effective swap rate at December 31, 2005 and 2004.

(d) Includes amounts due within one year and the effects of interest rate swaps.

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

At December 31, 2005 and 2004, our portfolio of long-term debt was substantially comprised of fixed rate instruments. Therefore, the fair value of the portfolio is relatively sensitive to effects of interest rate fluctuations. This sensitivity is illustrated by the $152 million increase in the fair value of long-term debt 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 would unfavorably affect our results and cash flows only if we would elect to repurchase or otherwise retire all or a portion of its fixed-rate debt portfolio 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, by individual debt instrument, the interest rate swap activity as of December 31, 2005:

Floating Rate to be Paid	Fixed Rate to be Received	Notional Amount	Swap Maturity	Fair Value

Six Month LIBOR +4.226%	6.650%	$ 300 million	2006	$ (1) million
Six Month LIBOR +1.935%	5.375%	$ 450 million	2007	$ (8) million
Six Month LIBOR +3.285%	6.850%	$ 400 million	2008	$ (11) million
Six Month LIBOR +2.142%	6.125%	$ 200 million	2012	$ (10) million

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Foreign Currency Exchange Rate Risk

We manage our exposure to foreign currency exchange rates by utilizing forward and option contracts, generally with terms of 365 days or less. 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, 2005, the following currency derivatives were outstanding. All contracts currently qualify for hedge accounting unless noted.

Financial Instruments	Period		Notional Amount	Collar Strike Range[a]	Fair Value[b]
Foreign Currency Rate Option Collars					
Euro	January 2006	June 2006	$ 81 million	1.17 1.22[c]	$
Norwegian kroner	January 2006	June 2006	$ 154 million	6.42 6.95[d]	$

[a] Rates shown are weighted average floor and ceiling prices for the period. If exchange rates are within the specified collar range at expiration, the collar expires worthless. If exchange rates are outside of the various collar ranges at expiration, we will settle the difference with the counterparty.

[b] Fair value was based on market prices.

[c] U.S. dollar to foreign currency.

[d] Foreign currency to U.S. dollar.

The aggregate effect on foreign exchange and option contracts of a hypothetical 10 percent change to year-end exchange rates would be approximately $15 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 2005 Consolidated Financial Statements and Supplementary Data

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Management s Responsibilities for Financial Statements

To the Stockholders of Marathon Oil Corporation:

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

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

The Board of Directors pursues its oversight role in the area of financial reporting and internal control over financial reporting through its Audit 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	Albert G. Adkins
President and	*Senior Vice President*	*Vice President,*
Chief Executive Officer	*and Chief Financial Officer*	*Accounting*

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, 2005. This evaluation did not include the internal control over financial reporting related to Marathon s Libya operations acquired in a purchase business combination on December 29, 2005. Under the terms of the agreement, the operational re-entry date is January 1, 2006; therefore, Marathon s consolidated results of operations for 2005 do not include any results from the Libya operations. Total assets recorded for the Libya operations as of December 31, 2005 represent approximately 4 percent of total assets as of that date.

Marathon s management assessment of the effectiveness of Marathon s internal control over financial reporting as of December 31, 2005 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	*Senior Vice President*
Chief Executive Officer	*and Chief Financial Officer*

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Report of Independent Registered Public Accounting Firm

To the Stockholders of Marathon Oil Corporation:

We have completed integrated audits of Marathon Oil Corporation and its subsidiaries (Marathon) 2005 and 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2005, and an audit of its 2003 consolidated financial statements 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 accompanying consolidated financial statements present fairly, in all material respects, the financial position of Marathon at December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of Marathon 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 financial statements, Marathon changed its method of accounting for conditional asset retirement obligations in 2005 and its method of accounting for asset retirement obligations in 2003.

Internal control over financial reporting

Also, in our opinion, management s assessment, included in the accompanying Management s Report on Internal Control over Financial Reporting, that Marathon maintained effective internal control over financial reporting as of December 31, 2005 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, 2005, based on criteria established in *Internal Control Integrated Framework* issued by the COSO. Marathon 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 Marathon 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.

As described in the accompanying Management s Report on Internal Control over Financial Reporting, management has excluded Marathon s Libya operations from its assessment of internal control over financial reporting as of December 31, 2005 because it was acquired by Marathon in a purchase business combination in December 2005. We have also excluded the Libya operations from our audit of internal control over financial reporting. The Libya operations total assets and total revenues represent 4% and 0%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2005.

PricewaterhouseCoopers LLP
Houston, Texas
March 3, 2006

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Consolidated Statements of Income

(Dollars in millions, except per share data)	**2005**	2004	2003
Revenues and other income:			
Sales and other operating revenues (including consumer excise taxes)	**$49,273**	$39,305	$32,859
Revenues from matching buy/sell transactions	**12,636**	9,242	7,183
Sales to related parties	**1,402**	1,051	921
Income from equity method investments	**266**	170	29
Net gains on disposal of assets	**57**	36	166
Gain (loss) on ownership change in Marathon Petroleum Company LLC		2	(1)
Other income net	**39**	101	77
Total revenues and other income	**63,673**	49,907	41,234
Costs and expenses:			
Cost of revenues (excluding items shown below)	**37,847**	30,740	24,900
Purchases related to matching buy/sell transactions	**12,364**	9,050	7,213
Purchases from related parties	**225**	202	209
Consumer excise taxes	**4,715**	4,463	4,285
Depreciation, depletion and amortization	**1,358**	1,217	1,144
Selling, general and administrative expenses	**1,158**	1,025	920
Other taxes	**482**	338	299
Exploration expenses	**222**	202	180
Total costs and expenses	**58,371**	47,237	39,150
Income from operations	**5,302**	2,670	2,084
Net interest and other financing costs	**145**	161	186
Minority interests in income (loss) of:			
Marathon Petroleum Company LLC	**384**	532	302
Equatorial Guinea LNG Holdings Limited	**(8)**	(7)	
Income from continuing operations before income taxes	**4,781**	1,984	1,596
Provision for income taxes	**1,730**	727	584
Income from continuing operations	**3,051**	1,257	1,012
Discontinued operations		4	305
Income before cumulative effect of changes in accounting principles	**3,051**	1,261	1,317
Cumulative effect of changes in accounting principles	**(19)**		4
Net income	**$ 3,032**	$ 1,261	$ 1,321

Per Share Data

Basic:			
Income from continuing operations	**$ 8.57**	$ 3.74	$ 3.26
Net income	**$ 8.52**	$ 3.75	$ 4.26
Diluted:			
Income from continuing operations	**$ 8.49**	$ 3.72	$ 3.26
Net income	**$ 8.44**	$ 3.73	$ 4.26

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

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Consolidated Balance Sheets

(Dollars in millions, except per share data) December 31	**2005**	2004
Assets		
Current assets:		
Cash and cash equivalents	**$ 2,617**	$ 3,369
Receivables, less allowance for doubtful accounts of $3 and $6	**3,476**	3,146
Receivables from United States Steel	**20**	15
Receivables from related parties	**38**	74
Inventories	**3,041**	1,995
Other current assets	**191**	267
Total current assets	**9,383**	8,866
Investments and long-term receivables, less allowance for doubtful accounts of $10 and $10	**1,864**	1,546
Receivables from United States Steel	**532**	587
Property, plant and equipment net	**15,011**	11,810
Prepaid pensions		128
Goodwill	**1,307**	252
Intangibles net	**200**	118
Other noncurrent assets	**201**	116
Total assets	**$28,498**	$23,423
Liabilities		
Current liabilities:		
Accounts payable	**$ 5,353**	$ 4,430
Consideration payable under Libya re-entry agreement	**732**	
Payables to related parties	**82**	44
Payroll and benefits payable	**344**	274
Accrued taxes	**782**	397
Deferred income taxes	**450**	
Accrued interest	**96**	92
Long-term debt due within one year	**315**	16
Total current liabilities	**8,154**	5,253
Long-term debt	**3,698**	4,057
Deferred income taxes	**2,030**	1,553
Employee benefit obligations	**1,321**	989
Asset retirement obligations	**711**	477
Payables to United States Steel	**6**	5
Deferred credits and other liabilities	**438**	288
Total liabilities	**16,358**	12,622
Minority interest in Marathon Petroleum Company LLC		2,559
Minority interests in Equatorial Guinea LNG Holdings Limited	**435**	131

Commitments and contingencies		
Stockholders Equity		
Common stock issued 366,925,852 shares at December 31, 2005 and 346,717,785 shares at December 31, 2004 (par value $1 per share, 550,000,000 shares authorized)	**367**	347
Common stock held in treasury, at cost 179,977 shares at December 31, 2005 and 34,650 shares at December 31, 2004	**(8)**	(1)
Additional paid-in capital	**5,111**	4,028
Retained earnings	**6,406**	3,810
Accumulated other comprehensive loss	**(151)**	(64)
Unearned compensation	**(20)**	(9)
Total stockholders equity	**11,705**	8,111
Total liabilities and stockholders equity	**$28,498**	$23,423

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

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Consolidated Statements of Cash Flows

(Dollars in millions)	**2005**	2004	2003
Increase (decrease) in cash and cash equivalents			
Operating activities			
Net income	**$ 3,032**	$ 1,261	$ 1,321
Adjustments to reconcile net income to net cash provided from operating activities:			
Cumulative effect of changes in accounting principles	**19**		(4)
Income from discontinued operations		(4)	(305)
Deferred income taxes	**(208)**	(73)	71
Minority interests in income of subsidiaries	**376**	525	302
Depreciation, depletion and amortization	**1,358**	1,217	1,144
Pension and other postretirement benefits net	**71**	82	68
Exploratory dry well costs and unproved property impairments	**113**	106	86
Net gains on disposal of assets	**(57)**	(36)	(166)
Impairment of investments			129
Changes in the fair value of long-term U.K. natural gas contracts	**386**	99	66
Changes in working capital:			
Current receivables	**(1,171)**	(709)	(671)
Inventories	**(150)**	(41)	33
Current accounts payable and accrued expenses	**1,067**	1,224	496
All other net	**(98)**	115	112
Net cash provided from continuing operations	**4,738**	3,766	2,682
Net cash provided from discontinued operations			83
Net cash provided from operating activities	**4,738**	3,766	2,765
Investing activities			
Capital expenditures	**(2,890)**	(2,247)	(1,909)
Acquisitions	**(506)**		(252)
Disposal of discontinued operations			612
Disposal of assets	**131**	76	644
Proceeds from sale of minority interests in Equatorial Guinea LNG Holdings Limited	**163**		
Restricted cash deposits	**(54)**	(42)	(108)
withdrawals	**41**	34	146
Investments loans and advances	**(27)**	(156)	(91)
All other net	**15**	11	2
Investing activities of discontinued operations			(29)
Net cash used in investing activities	**(3,127)**	(2,324)	(985)
Financing activities			
Payment of debt assumed in acquisitions	**(1,920)**		(31)
Commercial paper and revolving credit arrangements net			(131)

Debt issuance costs		(4)	
Other debt repayments	**(8)**	(259)	(177)
Issuance of common stock	**85**	1,047	17
Purchases of common stock	**(7)**	(4)	(6)
Dividends paid	**(436)**	(348)	(298)
Contributions from minority shareholders of Equatorial Guinea LNG Holdings Limited	**213**	95	
Distributions to minority shareholder of Marathon Petroleum Company LLC	**(272)**		(262)
Net cash provided from (used in) financing activities	**(2,345)**	527	(888)
Effect of exchange rate changes on cash			
Continuing operations	**(18)**	4	8
Discontinued operations			8
Net increase (decrease) in cash and cash equivalents	**(752)**	1,973	908
Cash and cash equivalents at beginning of year	**3,369**	1,396	488
Cash and cash equivalents at end of year	**$ 2,617**	$ 3,369	$ 1,396

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

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Consolidated Statements of Stockholders Equity

(Dollars in millions, except per share data)	Stockholders Equity			Shares in thousands		
	2005	2004	2003	**2005**	2004	2003
Common stock:						
Balance at beginning of year	**$ 347**	$ 312	$ 312	**346,718**	312,166	312,166
Issuance[(a)]	**20**	35		**20,208**	34,552	
Balance at end of year	**$ 367**	$ 347	$ 312	**366,926**	346,718	312,166
Common stock held in treasury, at cost:						
Balance at beginning of year	**$ (1)**	$ (46)	$ (60)	**(35)**	(1,744)	(2,293)
Repurchased	**(7)**	(4)	(6)	**(10)**	(129)	(219)
Reissued for employee stock plans		49	20	**(135)**	1,838	768
Balance at end of year	**$ (8)**	$ (1)	$ (46)	**(180)**	(35)	(1,744)

				Comprehensive Income		
				2005	2004	2003
Additional paid-in capital:						
Balance at beginning of year	**$ 4,028**	$ 3,033	$ 3,032			
Common stock issuance[(a)]	**1,065**	970				
Treasury stock reissued	**18**	25	1			
Balance at end of year	**$ 5,111**	$ 4,028	$ 3,033			
Unearned compensation:						
Balance at beginning of year	**$ (9)**	$ (9)	$ (7)			
Changes during year	**(11)**		(2)			
Balance at end of year	**$ (20)**	$ (9)	$ (9)			
Retained earnings:						
Balance at beginning of year	**$ 3,810**	$ 2,897	$ 1,874			
Net income	**3,032**	1,261	1,321	**$ 3,032**	$ 1,261	$ 1,321
Dividends paid (per share: $1.22 in 2005, $1.03 in 2004 and $0.96 in 2003)	**(436)**	(348)	(298)			
Balance at end of year	**$ 6,406**	$ 3,810	$ 2,897			

Accumulated other comprehensive loss[b] :						
Minimum pension liability adjustments:						
Balance at beginning of year	**$ (71)**	$ (93)	$ (47)			
Changes during year	**(70)**	22	(46)	**(70)**	22	(46)
Balance at end of year	**$ (141)**	$ (71)	$ (93)			
Foreign currency translation adjustments:						
Balance at beginning of year	**$ (5)**	$ (4)	$ (1)			
Changes during year		(1)	(3)		(1)	(3)
Balance at end of year	**$ (5)**	$ (5)	$ (4)			
Deferred gains (losses) on derivative instruments:						
Balance at beginning of year	**$ 12**	$ (15)	$ (21)			
Reclassification of the cumulative effect adjustment into income	**(2)**	(3)	(3)	**(2)**	(3)	(3)
Changes in fair value	**(15)**	(82)	(50)	**(15)**	(82)	(50)
Reclassification to income		112	59		112	59
Balance at end of year	**$ (5)**	$ 12	$ (15)			
Total balances at end of year	**$ (151)**	$ (64)	$ (112)			
Total comprehensive income				**$ 2,945**	$ 1,309	$ 1,278
Total stockholders equity	**$ 11,705**	$ 8,111	$ 6,075			

(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.

(b) Related income tax provision (credit) on changes and reclassifications during the year:

	2005	2004	2003
Minimum pension liability adjustments	**$ (42)**	$ 3	$ (25)
Foreign currency translation adjustments			(2)
Net deferred gains (losses) on derivative instruments	**(3)**	9	3

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

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Notes to Consolidated Financial Statements

1. Summary of Principal Accounting Policies

Marathon Oil Corporation (Marathon) is engaged in worldwide exploration and production of crude oil and natural gas; domestic refining, marketing and transportation of crude oil and petroleum products; and worldwide marketing and transportation of natural gas and products manufactured from natural gas.

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 5, 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 variable interest entities (VIEs) for which Marathon is the primary beneficiary are consolidated. Equatorial Guinea LNG Holdings Limited (EGHoldings), in which Marathon holds a 60% interest and was formed for the purpose of constructing and operating a liquefied natural gas (LNG) plant, is a VIE and Marathon is its primary beneficiary. As of December 31, 2005, total expenditures of $1.116 billion related to the LNG plant, including $1.066 billion of capital expenditures, have been incurred.

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 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 investment and the separate net asset value of the investee, if any, are amortized into income over the remaining useful life of the underlying assets. Income from equity method investments represents Marathon s proportionate share of 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 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 net income per share is calculated based on the weighted average number of common shares outstanding. Diluted net 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 and produces 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 natural gas and products manufactured from natural gas, such as LNG and methanol, on a worldwide basis.

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 to make decisions about resources to be allocated and to assess performance and (3) for which discrete financial information is available. The chief operating decision maker (CODM) is responsible for allocating resources to and assessing performance of Marathon s operating segments. Information on 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. In this role, the CODM is responsible for allocating resources within those segments, reviewing financial results of components within those segments, and assessing the performance of the components. The components within these 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 segment manager of the RM&T segment reports to the CODM. The RM&T segment manager is responsible for allocating resources within the segment, reviewing financial results of components within the segment, and assessing the performance of the components. The CODM reviews these financial results at the RM&T segment level.

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Segment income represents income from operations allocable to operating segments. Marathon s corporate general and administrative costs are not allocated to operating segments. These costs primarily consist of employment costs (including pension effects), professional services, facilities and other costs associated with corporate activities. These costs also include non-cash effects of stock-based compensation for all employees except those of MPC. Non-cash effects of stock-based compensation for MPC employees are allocated to the RM&T segment. 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 income from operations in Note 8.

Revenue recognition Revenues are recognized when products are shipped or services are provided to customers, 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 United States and certain international locations, production volumes of liquid hydrocarbons and natural gas are sold immediately and transported via pipeline. At other 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 to 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 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 Marathon considers matching buy/sell transactions to be arrangements in which Marathon agrees to buy a specific quantity and quality of crude oil or refined petroleum products to be delivered at a specific location while simultaneously agreeing to sell a specified quantity and quality of crude oil or refined petroleum products at a different location, usually with the same counterparty. All matching buy/sell transactions are settled in cash and are recorded in both revenues and cost of revenues as separate sales and purchase transactions, or on a gross basis. The commodity purchased and the commodity sold generally are similar in nature.

In a typical matching buy/sell transaction, Marathon enters into a contract to sell a particular grade of crude oil or refined product at a specified location and date to a particular counterparty, and simultaneously agrees to buy a particular grade of crude oil or refined product at a different location on the same or another specified date, typically 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.

The characteristics of Marathon s matching buy/sell transactions include gross invoicing between Marathon and its counterparties and cash settlement of the transactions. Nonperformance by one party to deliver generally does not relieve the other party s obligation to perform. Both transactions require physical delivery of the product. The risks and rewards of ownership are evidenced by title transfer, assumption of environmental risk, transportation scheduling, credit risk, counterparty nonperformance risk and the fact that Marathon has the primary obligation to perform.

Marathon will be required to change its accounting for purchases and sales of inventory with the same counterparty, including certain matching buy/sell transactions, in the second quarter of 2006. See Note 30 for further information.

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.

Inventories Inventories are carried at lower of cost or market. 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.

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 for doubtful accounts 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.

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 and refined products, 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 derivatives are recognized immediately in income, in revenues, other income, cost of revenues or net interest and other financing costs, 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 and interest rate risk, as well as 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 accumulated other comprehensive income, a component of stockholders equity, and is reclassified to income in revenues, cost of revenues, depreciation, depletion and amortization or net interest and other financing costs when the underlying forecasted transaction is recognized in income. Any ineffective portion of such hedges is recognized in income as it occurs. For discontinued cash flow hedges, prospective changes in the fair value of the derivative are recognized in income. Any gain or loss in accumulated 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 related gain or loss in accumulated other comprehensive income is immediately reclassified into 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 income in revenues, cost of revenues or net interest and other financing costs with an offsetting effect included in the basis of the hedged item. The net effect is to report in income the extent to which the hedge is not effective in achieving offsetting changes in fair value.

As market conditions change, Marathon may use selective derivative instruments that assume market risk. For derivative instruments that are classified as trading, changes in the fair value are recognized immediately in other income. Any premium received is amortized into income based on the underlying settlement terms of the derivative position. All related effects of a trading strategy, including physical settlement of the derivative position, are recognized in 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 in the balance sheet at fair value and changes in fair values are recognized in income as 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 involve flash title are also accounted for as nontraditional derivative instruments as Marathon has not elected to treat these contracts as normal purchases or normal sales.

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 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 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 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.

Major maintenance activities Marathon incurs costs for planned major refinery maintenance (turnarounds). Such costs are expensed in the same annual period as incurred; however, estimated annual turnaround costs are recognized as expense throughout the year on a pro rata basis.

Environmental remediation liabilities Environmental remediation expenditures are capitalized if the costs mitigate past 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

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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.

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. Upon adoption of Financial Accounting Standards Board (FASB) Interpretation (FIN) No. 47, Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No. 143, on December 31, 2005, conditional asset retirement obligations for removal and disposal of fire-retardant material from certain refining facilities were recognized based on the most probable current cost projections. See Note 2 for further information regarding Marathon s adoption of FIN No. 47.

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. The depreciation will generally be determined on a units-of-production basis for production facilities and on a straight-line basis for refining facilities, while the accretion to be recognized will escalate 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 has noncontributory defined benefit pension plans covering substantially all domestic employees as well as international employees located in Ireland, Norway and the United Kingdom. In addition, several excess benefits plans exist covering domestic employees within defined regulatory compensation limits. Benefits under these plans are based primarily on years of service and final average pensionable earnings. The benefits provided include both pension and health care.

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.

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

Stock-based compensation The Marathon Oil Corporation 2003 Incentive Compensation Plan (the Plan) authorizes the Compensation Committee of the Board of Directors of Marathon 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, expire unexercised, settled in cash, exchanged for other awards, tendered to satisfy the purchase price of an award, withheld to satisfy tax obligations or otherwise lapse become available for future grants.

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 (collectively, 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.

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. Prior to 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 all expire ten years from the date they are granted.

Similar to stock options, stock appreciation rights (SARs) 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 exercise price. In general, SARs that have been granted under the Plan are settled in shares of stock, vest ratably over a three-year period and have a maximum term of ten years from the date they are granted.

In 2003 and 2004, the Compensation Committee granted stock-based Performance Awards to Marathon s officers under the Plan. 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 generally vest at the end of a 36-month performance period if certain pre-established performance targets are achieved and the recipient remains employed by Marathon at that date.

In 2005, the Compensation Committee granted cash-based Performance Awards to Marathon s and MPC s officers under the Plan. The cash-based performance units generally vest at the end of a 36-month performance period if certain pre-established performance targets are achieved and the recipient remains employed by Marathon at that date. The target value of each performance unit granted is $1, with the actual payout varying from zero percent to 200 percent of the target value based on actual performance achieved. The Compensation Committee also granted time-based restricted stock to the officers under the Plan in 2005. The restricted stock awards vest three years from the date of grant, contingent on the recipient s continued employment. Prior to vesting, the restricted stock recipients have the right to vote such stock and receive dividends thereon. The nonvested shares are not transferable and are retained by Marathon until they vest.

Marathon also grants restricted stock to certain non-officer employees under the Plan based on their performance within certain guidelines and for retention purposes. The restricted stock awards generally vest in one-third increments over a three-year period, contingent on the recipient s continued employment. Prior to vesting, the restricted stock recipients have the right to vote such stock and receive dividends thereon. The nonvested shares are not transferable and are retained by Marathon until they vest.

Unearned compensation is charged to stockholders equity when restricted stock and performance shares are granted. Compensation expense is recognized over the balance of the vesting period and is adjusted if conditions of the restricted stock or performance share grant are not met. Cash-based performance units are classified as a liability and compensation expense is recognized over the 36-month performance period based on expected payout.

Marathon maintains an equity compensation program for its non-employee directors under the Plan. Pursuant to the program, non-employee directors must defer 50 percent of their annual retainers in the form of common stock units. In addition, each non-employee director receives an annual grant of non-retainer common stock units under the Plan. In 2005, the value of each grant was $60,000. The program also provides each non-employee director with a matching grant of up to 1,000 shares of common stock on his or her initial election to the Board if he or she purchases an equivalent number of shares within 60 days of joining the Board.

Effective January 1, 2003, Marathon has applied the fair value based method of accounting to all grants and any modified grants of stock-based compensation. All prior outstanding and unvested awards continue to be accounted for under the intrinsic value method. The following net income and per share data illustrates the effect on net income and net income per share if the fair value method had been applied to all outstanding and unvested awards in each period.

(In millions, except per share data)	**2005**	2004	2003
Net income:			
As reported	**$ 3,032**	$ 1,261	$ 1,321

Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	**72**	39	23
Deduct: Total stock-based employee compensation expense determined under the fair value method for all awards, net of related tax effects	**(72)**	(32)	(17)
Pro forma net income	**$ 3,032**	$ 1,268	$ 1,327
Basic net income per share:			
As reported	**$ 8.52**	$ 3.75	$ 4.26
Pro forma	**$ 8.52**	$ 3.77	$ 4.28
Diluted net income per share:			
As reported	**$ 8.44**	$ 3.73	$ 4.26
Pro forma	**$ 8.44**	$ 3.75	$ 4.28

Marathon records compensation cost over the stated vesting period for stock options 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. Upon adoption of Statement of Financial Accounting Standards (SFAS) No. 123 (Revised 2004), Share-Based Payment, such compensation cost will be 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. The compensation cost determined under these two approaches did not differ materially for the periods presented above.

The above pro forma amounts were based on a Black-Scholes option-pricing model, which included the following information and assumptions:

	2005	2004	2003
Weighted-average grant-date exercise price per share	**$ 50.28**	$ 33.61	$ 25.58
Expected annual dividends per share	**$ 1.32**	$ 1.00	$ 0.97
Expected life in years	**5.5**	5.5	5.0
Expected volatility	**28%**	32%	34%
Risk-free interest rate	**3.8%**	3.9%	3.0%
Weighted-average grant-date fair value of options granted during the year, as calculated from above	**$ 12.30**	$ 8.83	$ 5.37

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 Separation. These exposures are discussed in Note 3.

Reclassifications Certain reclassifications of prior years data have been made to conform to 2005 classifications.

2. New Accounting Standards

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

The pro forma net income and net income per share effect as if FIN No. 47 had been applied during 2005, 2004 and 2003 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)	
January 1, 2003	$ 384
December 31, 2003	438
December 31, 2004	527
December 31, 2005	711

In December 2004, the FASB issued SFAS No. 153, Exchanges of Nonmonetary Assets an amendment of APB Opinion No. 29. This amendment eliminates the Accounting Principles Board (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. Marathon adopted SFAS No. 153 on a prospective basis as of July 1, 2005.

Effective January 1, 2005, Marathon adopted FASB Staff Position (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 14.

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 qualified production activities income as a special deduction in the years taken.

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 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.

Effective July 1, 2004, Marathon adopted FSP No. FAS 142-2, Application of FASB Statement No. 142, *Goodwill and Other Intangible Assets,* to Oil- and Gas-Producing Entities. FSP No. FAS 142-2 states drilling and mineral rights of oil- and gas-producing entities are excluded from SFAS No. 142, Goodwill and Other Intangible Assets, and accordingly, should not be classified as intangible assets rather than oil and gas properties. The adoption of FSP No. FAS 142-2 did not have an effect on Marathon s consolidated financial position, cash flows or results of operations.

Effective January 1, 2003, Marathon adopted the provisions of SFAS No. 145, Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections, relating to the classification of the effects of early extinguishment of debt in the consolidated statement of income. As a result, losses from the early extinguishment of debt, which were previously reported as an extraordinary item, will be included in income from continuing operations before income taxes.

Effective January 1, 2003, Marathon adopted the fair value recognition provisions of SFAS No. 123, Accounting for Stock-Based Compensation. SFAS No. 148, Accounting for Stock-Based Compensation Transition and Disclosure, an amendment of SFAS No. 123, provides alternative methods for the transition of accounting for stock-based compensation from the intrinsic value method to the fair value method. Marathon has applied the fair value method to grants made, modified or settled on or after January 1, 2003.

Effective January 1, 2003, Marathon adopted SFAS No. 143, Accounting for Asset Retirement Obligations. The transition adjustment related to adopting SFAS No. 143, was recognized as a cumulative effect of a change in accounting principle. The cumulative effect on net income of adopting SFAS No. 143 was a net favorable effect of $4 million, net of tax of $4 million. At the time of adoption, total assets increased $120 million, and total liabilities increased $116 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

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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.

The Tax Sharing Agreement incorporates the general tax sharing principles of the former tax allocation policy. In general, Marathon and United States Steel will make payments between them such that, with respect to any consolidated, combined or unitary tax returns for any taxable period or portion thereof ending on or before the Separation Date, the amount of taxes to be paid by each of Marathon and United States Steel will be determined, subject to certain adjustments, as if the former groups each filed their own consolidated, combined or unitary tax return. The Tax Sharing Agreement also provides for payments between Marathon and United States Steel for certain tax adjustments that may be made after the Separation. Other provisions address, but are not limited to, the handling of tax audits, settlements and return filing in cases where both Marathon and United States Steel have an interest in the results of these activities.

In 2005, 2004 and 2003, in accordance with the terms of the tax sharing agreement, Marathon paid $6 million, $3 million and $16 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 1992 through 1997. Included in discontinued operations in 2003 is an $8 million adjustment to the liabilities to United States Steel under this tax sharing agreement.

Relationship between Marathon and United States Steel after the Separation As a result of the Separation, Marathon and United States Steel are separate companies and neither has any ownership interest in the other. As of December 31, 2005, Thomas J. Usher was the non-executive chairman of the board of both companies and four of the ten remaining members of Marathon s board of directors are also directors of United States Steel. Mr. Usher retired as chairman of United States Steel on January 31, 2006. At that date, he and one other Marathon board member left United States Steel s board of directors.

Sales to United States Steel in 2005, 2004 and 2003 were $31 million, $30 million and $31 million, primarily for natural gas. Purchases from United States Steel in 2005, 2004 and 2003 were $39 million, $27 million and $14 million, primarily for raw materials. Management believes that transactions with United States Steel were conducted under terms comparable to those with unrelated parties. Marathon reimbursed United States Steel $1 million and $3 million, respectively, in 2005 and 2004, for the payment of benefits to retirees, including Mr. Usher, under United States Steel s 2001 plan of reorganization.

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.

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At December 31, 2005 and 2004, amounts receivable from or payable to United States Steel included in the consolidated balance sheets were as follows:

(In millions) December 31	2005	2004
Receivables related to debt and other obligations for which United States Steel has assumed responsibility for repayment:		
Current	**$ 20**	$ 15
Noncurrent	**532**	587
Noncurrent reimbursements payable under nonqualified employee benefit plans	**$ 6**	$ 5

Marathon remains primarily obligated for $45 million of operating lease obligations assumed by United States Steel, of which $37 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 28 for additional details on these guarantees.

4. Related Party Transactions

Related parties include:

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

Compania Nacional de Petroleos de Guinea Ecuatorial (GEPetrol), Mitsui & Co., Ltd. (Mitsui) and Marubeni Corporation (Marubeni), which hold ownership interests in EGHoldings, a consolidated subsidiary; 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 Ashland and Pilot Travel Centers LLC (PTC) consist primarily of petroleum products. Revenues from related parties were as follows:

(In millions)	2005	2004	2003
Ashland	**$ 132**	$ 274	$ 258
Equity method investees:			
PTC	**1,205**	715	635
Centennial Pipeline LLC (Centennial)	**47**	49	16
Other	**18**	13	12
Total	**$ 1,402**	$ 1,051	$ 921

Purchases from related parties were as follows:

(In millions)	2005	2004	2003

Ashland	**$ 12**	$ 22	$ 24
Equity method investees:			
Centennial	**73**	56	49
Other	**140**	124	136
Total	**$ 225**	$ 202	$ 209

Receivables from related parties were as follows:

(In millions) December 31	**2005**	2004
Ashland	**$**	$ 18
Equity method investees:		
PTC	**34**	19
Alba Plant LLC	**3**	17
Centennial		16
Other	**1**	4
Total	**$ 38**	$ 74

Payables to related parties were as follows:

(In millions) December 31	**2005**	2004
GEPetrol	**$ 57**	$ 23
Equity method investees:		
Alba Plant LLC	**14**	
Centennial	**1**	12
Other	**10**	9
Total	**$ 82**	$ 44

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, 2004 and 2003.

Cash of $57 million held in escrow for future contributions to EGHoldings from GEPetrol is classified as restricted cash and is included in investments and long-term receivables as of December 31, 2005.

5. 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	58
Transaction-related costs	10
Purchase price	2,421
Assumption of debt[c]	1,920
Total consideration including debt assumption[d]	$ 4,341

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

(b) Ashland shareholders received 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.

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

(d) Marathon is entitled to the tax deductions for Ashland s future payments of certain contingent liabilities 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 these future payments. This contingent consideration will be included in the purchase price as such payments are made to Ashland.

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

- Marathon believes the outlook for the refining and marketing business is attractive in MPC s core areas of operation. Complete ownership of MPC provides Marathon the opportunity to leverage MPC s access to premium U.S. markets where Marathon expects the levels of demand to remain high for the foreseeable future;
- The Acquisition increases Marathon s participation in the RM&T business without the risks commonly associated with integrating a newly acquired business;
- MPC provides Marathon with an increased source of cash flow which Marathon believes enhances the geographical balance in its overall risk portfolio;
- Marathon anticipates the transaction will 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	735
Intangibles	112
Other noncurrent assets	8
Total assets acquired	$ 7,502
Current liabilities:	
Notes payable	$ 1,920
Deferred income taxes	669
Other current liabilities	1,694
Total current liabilities assumed	4,283
Long-term debt	16
Deferred income taxes	265
Employee benefits obligations	484
Other liabilities	33
Total liabilities assumed	$ 5,081

Net assets acquired	$ 2,421

The goodwill arising from the purchase price allocation was $735 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 life 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 a payment of $520 million from Marathon, which was made in January 2006. An additional payment estimated to be approximately $212 million is payable by Marathon within one year of the agreement date.

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

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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 is 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. Marathon is in the process of finalizing the fair value estimates for certain assets and liabilities; thus the allocation of the purchase price is preliminary.

(In millions)

Current assets:		
Inventories	$	10
Other current assets		8
Total current assets acquired		18
Property, plant and equipment		732
Goodwill		315
Total assets acquired	$	1,065
Current liabilities:		
Accounts payable	$	10
Other liabilities		4
Deferred income taxes		319
Total liabilities assumed	$	333
Net assets acquired	$	732

The goodwill arising from the preliminary purchase price allocation was $315 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	**$**	**64,829**	$	50,803
Income from continuing operations		**3,807**		1,559
Net income		**3,290**		1,563
Per share data:				
Income from continuing operations basic	**$**	**10.44**	$	4.40
Income from continuing operations diluted	**$**	**10.35**	$	4.38
Net income basic	**$**	**9.02**	$	4.42
Net income diluted	**$**	**8.95**	$	4.39

Khanty Mansiysk Oil Corporation

On May 12, 2003, Marathon acquired Khanty Mansiysk Oil Corporation (KMOC) for $285 million, including the assumption of $31 million in debt. KMOC is engaged in evaluating or developing nine oil fields in the Khanty-Mansiysk region of western Siberia in the Russian Federation. Results of operations for 2003 include the results of KMOC from May 12, 2003.

The following unaudited pro forma data for Marathon includes the results of operations of KMOC giving effect to the acquisition as if it had been consummated at the beginning of the period presented. The pro forma data is based on historical information and does not necessarily represent the actual results that would have occurred nor is it necessarily indicative of future results of operations.

(In millions, except per share amounts)	2003
Revenues and other income	$ 41,257
Income from continuing operations	1,005
Net income	1,314
Per share data:	
Income from continuing operations basic and diluted	$ 3.24
Net income basic and diluted	$ 4.23

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6. Discontinued Operations

On October 1, 2003, Marathon sold its exploration and production operations in western Canada for $612 million. This divestiture decision was made as part of Marathon s strategic plan to rationalize noncore oil and gas properties. The results of these operations have been reported separately as discontinued operations in the consolidated statements of income. The sale resulted in a gain of $278 million, including a tax benefit of $8 million, which has been reported in discontinued operations. Revenues applicable to the discontinued operations totaled $188 million for 2003. Pretax income from discontinued operations was $66 million for 2003. During 2004, the final working capital adjustment was determined, which resulted in an additional gain of $4 million that is reported in discontinued operations.

7. Income per Common Share

	2005		2004		2003	
(Dollars in millions, except per share data)	**Basic**	**Diluted**	Basic	Diluted	Basic	Diluted
Income from continuing operations	**$ 3,051**	**$ 3,051**	$ 1,257	$ 1,257	$ 1,012	$ 1,012
Income from discontinued operations			4	4	305	305
Cumulative effect of changes in accounting principles	**(19)**	**(19)**			4	4
Net income	**$ 3,032**	**$ 3,032**	$ 1,261	$ 1,261	$ 1,321	$ 1,321
Shares of common stock outstanding (thousands):						
Average number of common shares outstanding	**356,003**	**356,003**	336,485	336,485	310,129	310,129
Effect of dilutive securities stock options		**3,078**		1,768		197
Average common shares including dilutive effect	**356,003**	**359,081**	336,485	338,253	310,129	310,326
Per share:						
Income from continuing operations	**$ 8.57**	**$ 8.49**	$ 3.74	$ 3.72	$ 3.26	$ 3.26
Income from discontinued operations	**$**	**$**	$ 0.01	$ 0.01	$ 0.99	$ 0.99
Cumulative effect of changes in accounting principles	**$ (0.05)**	**$ (0.05)**	$	$	$ 0.01	$ 0.01

Net income	**$ 8.52**	**$ 8.44**	$ 3.75	$ 3.73	$ 4.26	$ 4.26

8. Segment Information

Revenues by product line were:

(In millions)	**2005**	2004	2003
Refined products	**$ 40,040**	$ 29,780	$ 24,092
Merchandise	**2,689**	2,489	2,395
Liquid hydrocarbons	**16,677**	13,860	10,500
Natural gas	**3,675**	3,266	3,796
Transportation and other	**230**	203	180
Total	**$ 63,311**	$ 49,598	$ 40,963

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

(In millions)	**2005**	2004	2003
Refined products	**$ 1,817**	$ 1,226	$ 826
Liquid hydrocarbons	**10,819**	8,016	6,357
Total	**$ 12,636**	$ 9,242	$ 7,183

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The following represents information by operating segment:

(In millions)	Exploration and Production	Refining, Marketing and Transportation	Integrated Gas	Total
2005				
Revenues:				
Customer	**$ 6,009**	**$ 54,414**	**$ 1,872**	**$ 62,295**
Intersegment[(a)]	**466**	**198**	**212**	**876**
Related parties	**11**	**1,391**		**1,402**
Segment revenues	**6,486**	**56,003**	**2,084**	**64,573**
Elimination of intersegment revenues	**(466)**	**(198)**	**(212)**	**(876)**
Loss on long-term U.K. natural gas contracts	**(386)**			**(386)**
Total revenues	**$ 5,634**	**$ 55,805**	**$ 1,872**	**$ 63,311**
Segment income	**$ 2,988**	**$ 3,013**	**$ 31**	**$ 6,032**
Income from equity method investments	**67**	**137**	**62**	**266**
Depreciation, depletion and amortization [(b)]	**849**	**468**	**9**	**1,326**
Capital expenditures[(c)]	**1,460**	**841**	**572**	**2,873**
2004				
Revenues:				
Customer	$ 4,618	$ 42,435	$ 1,593	$ 48,646
Intersegment[(a)]	370	152	146	668
Related parties	8	1,043		1,051
Segment revenues	4,996	43,630	1,739	50,365
Elimination of intersegment revenues	(370)	(152)	(146)	(668)
Loss on long-term U.K. natural gas contracts	(99)			(99)
Total revenues	$ 4,527	$ 43,478	$ 1,593	$ 49,598
Segment income	$ 1,696	$ 1,406	$ 48	$ 3,150
Income from equity method investments	20	81	69	170
Depreciation, depletion and amortization [(b)]	750	416	8	1,174
Capital expenditures[(c)]	944	794	490	2,228
2003				
Revenues:				
Customer	$ 4,460	$ 33,508	$ 2,140	$ 40,108
Intersegment[(a)]	405	97	108	610

Related parties	12	909		921
Segment revenues	4,877	34,514	2,248	41,639
Elimination of intersegment revenues	(405)	(97)	(108)	(610)
Loss on long-term U.K. natural gas contracts	(66)			(66)
Total revenues	$ 4,406	$ 34,417	$ 2,140	$ 40,963
Segment income	$ 1,580	$ 819	$ (3)	$ 2,396
Income from equity method investments[d]	50	82	21	153
Depreciation, depletion and amortization [b]	724	375	12	1,111
Capital expenditures[c]	973	789	131	1,893

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

[b] Differences between segment totals and Marathon totals represent impairments and amounts related to corporate administrative activities and are included in administrative expenses in the reconciliation below.

[c] Differences between segment totals and Marathon totals represent amounts related to corporate administrative activities.

[d] Excludes a $124 million loss on the dissolution of MKM Partners L.P., which was not allocated to segments. See Note 13.

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

(In millions)	**2005**	2004	2003
Segment income	**$ 6,032**	$ 3,150	$ 2,396
Items not allocated to segments:			
Administrative expenses	**(367)**	(307)	(227)
Losses on long-term U.K. natural gas contracts	**(386)**	(99)	(66)
Gain on sale of minority interests in EGHoldings	**23**		
Impairment of certain oil and gas properties		(44)	
Corporate insurance adjustment		(32)	
Gain on asset disposition			106
Loss on dissolution of MKM Partners L.P.			(124)
Gain (loss) on ownership changes in subsidiaries		2	(1)
Income from operations	**$ 5,302**	$ 2,670	$ 2,084

The information below summarizes the operations in different geographic areas. Transfers between affiliates are at prices that approximate market.

		Revenues			
(In millions)	Year	From Unaffiliated Customers	From Affiliates	Total	Assets[(a)]
United States	**2005**	**$ 60,242**	**$ 6**	**$ 60,248**	**$ 10,143**
	2004	47,354		47,354	8,396
	2003	39,377		39,377	8,061
United Kingdom	**2005**	**$ 1,569**	**$ 64**	**$ 1,633**	**$ 984**
	2004	995		995	1,076
	2003	849		849	1,215
Equatorial Guinea	**2005**	**$ 45**	**$ 598**	**$ 643**	**$ 3,018**
	2004	247		247	2,444
	2003	119		119	1,656
Other Foreign Countries	**2005**	**$ 1,455**	**$ 2,126**	**$ 3,581**	**$ 2,526**
	2004	1,002	1,868	2,870	1,231
	2003	618	1,352	1,970	1,073
Eliminations	**2005**	**$**	**$ (2,794)**	**$ (2,794)**	**$**
	2004		(1,868)	(1,868)	
	2003		(1,352)	(1,352)	
Total	**2005**	**$ 63,311**	**$**	**$ 63,311**	**$ 16,671**
	2004	49,598		49,598	13,147
	2003	40,963		40,963	12,005

(a) Includes property, plant and equipment and investments.

9. Other Items

Net interest and other financing costs

(In millions)	**2005**	2004	2003
Interest and other financial income:			
Interest income	**$ 78**	$ 45	$ 16
Foreign currency adjustments	**(17)**	9	13
Total	**61**	54	29
Interest and other financing costs:			
Interest incurred[a]	**257**	262	282
Less income from interest rate swaps		24	23
Less interest capitalized	**83**	48	41
Net interest expense	**174**	190	218
Interest on tax issues	**22**	12	(13)
Other	**10**	13	10
Total	**206**	215	215
Net interest and other financing costs	**$ 145**	$ 161	$ 186

[a] Excludes $34 million, $40 million and $34 million paid by United States Steel in 2005, 2004 and 2003 on assumed debt.

Foreign currency transactions

Aggregate foreign currency losses were included in the consolidated statements of income as follows:

(In millions)	**2005**	2004	2003
Net interest and other financing costs	**$ (17)**	$ 9	$ 13
Provision for income taxes	**(24)**	(15)	(15)
Aggregate foreign currency losses	**$ (41)**	$ (6)	$ (2)

10. Income Taxes

Provisions (credits) for income taxes were:

	2005			2004			2003		
(In millions)	**Current**	**Deferred**	**Total**	Current	Deferred	Total	Current	Deferred	Total
Federal	**$ 1,227**	**$ 16**	**$ 1,243**	$ 473	$ (22)	$ 451	$ 280	$ 95	$ 375
State and local	**171**	**12**	**183**	47	1	48	56	(4)	52
Foreign	**540**	**(236)**	**304**	280	(52)	228	177	(20)	157
Total	**$ 1,938**	**$ (208)**	**$ 1,730**	$ 800	$ (73)	$ 727	$ 513	$ 71	$ 584

A reconciliation of the federal statutory tax rate (35 percent) applied to income before income taxes to the total provisions for income taxes follows:

(In millions)	**2005**	2004	2003
Statutory rate applied to income before income taxes	**$ 1,673**	$ 694	$ 559
Effects of foreign operations, including foreign tax credits	**(44)**	26	(7)
State and local income taxes after federal income tax effects	**119**	32	35
Credits other than foreign tax credits	**(2)**	(2)	(6)
Domestic production activities deduction[a]	**(39)**		
Excess capital losses generated (utilized)	**23**	(4)	
Effects of partially owned companies	**(4)**	(3)	(6)
Adjustment of prior years federal income taxes	**10**	(11)	17
Other	**(6)**	(5)	(8)
Total provisions for income taxes	**$ 1,730**	$ 727	$ 584

[a] 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 for 2005 under the American Jobs Creation Act of 2004, as a special deduction.

Deferred tax assets and liabilities resulted from the following:

(In millions) December 31	2005	2004
Deferred tax assets:		
Net operating loss carryforwards	$	$ 2
Capital loss carryforwards (expiring in 2008 and 2010)	**79**	57
State tax loss carryforwards (expiring in 2006 through 2021)	**105**	122
Foreign tax loss carryforwards[a]	**649**	581
Expected federal benefit for:		
Crediting certain foreign deferred income taxes	**123**	292
Deducting state and foreign deferred income taxes	**183**	37
Employee benefits	**678**	341
Contingencies and other accruals	**295**	201
Derivative instruments	**196**	40
Investments in subsidiaries and equity method investees		4
Other	**101**	86
Valuation allowances[b]:		
Federal	**(120)**	(57)
State	**(72)**	(71)
Foreign	**(435)**	(365)
Total deferred tax assets[c]	**1,782**	1,270
Deferred tax liabilities:		
Property, plant and equipment	**3,072**	2,174
Inventory	**775**	304
Investments in subsidiaries and equity method investees	**94**	
Prepaid pensions	**47**	70
Other	**112**	88
Total deferred tax liabilities	**4,100**	2,636
Net deferred tax liabilities	**$ 2,318**	$ 1,366

(a) For 2005, includes $547 million for Norway and $54 million for Angola, both of which have no expiration dates. The remainder expire 2006 through 2019.

(b) Valuation allowances related to federal deferred tax assets are associated with capital loss carryforwards. The remaining valuation allowances are primarily associated with net operating loss carryforwards in several state jurisdictions, Norway, Angola and several other foreign jurisdictions.

(c) Marathon expects to generate sufficient future taxable income to realize the benefit of the deferred tax assets. In addition, the ability to realize the benefit of foreign tax credits is based on certain assumptions concerning future operating conditions (particularly as related to prevailing oil prices), income generated from foreign sources and Marathon s tax profile in the years that such credits may be claimed.

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

(In millions) December 31	2005	2004

Assets:				
Other current assets	**$**	**14**	$	127
Other noncurrent assets		**148**		60
Liabilities:				
Current deferred income taxes		**450**		
Noncurrent deferred income taxes		**2,030**		1,553
Net deferred tax liabilities	**$**	**2,318**	$	1,366

Marathon is continuously undergoing examination of its federal income tax returns by the Internal Revenue Service (IRS). Marathon and the IRS have settled tax years through 1997 and Marathon is in appeals for tax years 1998 through 2001. Audits for the tax years 2002 and 2003 are in progress and audits for tax years 2004 and 2005 will commence in 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 on occasion, 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 $1.127 billion in 2005, $534 million in 2004 and $453 million in 2003.

Undistributed income of certain consolidated foreign subsidiaries at December 31, 2005 amounted to $1.544 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 deferred tax liability of $541 million would have been required.

See Note 3 for a discussion of the Tax Sharing Agreement between Marathon and United States Steel.

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11. 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 and 2003, Marathon recorded $43 million and $24 million of costs as general and administrative expenses related to these business transformation programs. These charges included employee severance and benefit costs related to the elimination of approximately 700 regular employee positions, relocation costs, net benefit plans settlement and curtailment losses and fixed asset related costs.

There were minimal charges to expense during 2005 and, 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 and 2003.

(In millions)	Accrued January 1	Expense	Noncash Charges (Gains)	Cash Payments	Accrued December 31
2004					
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
2003					
Employee severance and termination benefits	$	$ 25	$	$ 13	$ 12
Net benefit plans settlement and curtailment gains		(10)	(10)		
Relocation costs		5			5
Fixed asset related costs		4	2	1	1
Total	$	$ 24	$ (8)	$ 14	$ 18

12. Inventories

(In millions) December 31	**2005**	2004
Liquid hydrocarbons and natural gas	**$ 1,093**	$ 676
Refined products and merchandise	**1,763**	1,192
Supplies and sundry items	**185**	127

Total (at cost)	**$ 3,041**	$ 1,995

The LIFO method accounted for 92 percent of total inventory value at December 31, 2005 and 2004. Current acquisition costs were estimated to exceed the LIFO inventory values at December 31, 2005 and 2004 by approximately $1,535 million and $1,294 million. Cost of revenues and income from operations showed no change in 2005 as a result of liquidations of LIFO inventories. Cost of revenues was reduced and income from operations was increased by $4 million in 2004, and $11 million in 2003 as a result of liquidations of LIFO inventories.

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13. Investments and Long-Term Receivables

(In millions) December 31	**2005**	2004
Equity method investments:		
Alba Plant LLC	**$ 513**	$ 432
Atlantic Methanol Production Company LLC	**258**	265
Pilot Travel Centers LLC	**516**	372
LOOP LLC	**148**	60
Other	**220**	205
Other investments	**5**	3
Recoverable environmental costs receivable	**57**	52
Value-added tax refunds receivable	**29**	32
Fair value of derivative assets	**14**	24
Deposits of restricted cash	**87**	89
Other receivables	**17**	12
Total	**$ 1,864**	$ 1,546

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

(In millions)	**2005**	2004	2003
Income data year:			
Revenues and other income	**$ 10,088**	$ 7,419	$ 7,036
Operating income	**556**	434	435
Net income	**474**	330	319
Balance sheet data December 31:			
Current assets	**$ 645**	$ 583	
Noncurrent assets	**3,598**	3,990	
Current liabilities	**668**	569	
Noncurrent liabilities	**1,477**	1,511	

Marathon s carrying value of its equity method investments is $643 million higher than the underlying net assets of investees. This basis difference is being amortized into 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 $200 million in 2005, $152 million in 2004, and $175 million in 2003.

On June 30, 2003, Marathon and Kinder Morgan Energy Partners, L.P. (Kinder Morgan) dissolved MKM Partners L.P. which had oil and gas production operations in the Permian Basin of Texas. Marathon held an 85 percent noncontrolling interest in the partnership. Prior to the dissolution of the partnership, Kinder Morgan acquired MKM Partners L.P. s 12.75 percent interest in the SACROC unit for an undisclosed amount. The partnership recorded a loss on the disposal of SACROC of $19 million, of which Marathon s share was $17 million. Also prior to the dissolution, Marathon recorded a $107 million impairment of its investment in MKM Partners L.P. due to an other-than-temporary decline in the fair value of the investment. The total loss recognized by Marathon related to the dissolution of MKM Partners L.P. was $124 million. The partnership s interest in the Yates field was distributed to Marathon and Kinder Morgan on dissolution.

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14. Property, Plant and Equipment

(In millions) December 31	2005	2004
Production	**$ 17,262**	$ 15,162
Refining	**4,727**	4,398
Marketing	**1,895**	1,954
Transportation	**1,980**	1,816
Gas liquefaction	**1,067**	524
Other	**464**	382
Total	**27,395**	24,236
Less accumulated depreciation, depletion and amortization	**12,384**	12,426
Net property, plant and equipment	**$ 15,011**	$ 11,810

Property, plant and equipment includes gross assets acquired under capital leases of $78 million and $49 million at December 31, 2005 and 2004, with related amounts in accumulated depreciation, depletion and amortization of $6 million and $6 million at December 31, 2005 and 2004.

Deferred exploratory well costs were as follows:

(Dollars in millions) December 31	2005	2004	2003
Amounts capitalized less than one year after completion of drilling	**$ 304**	$ 284	$ 165
Amounts capitalized greater than one year after completion of drilling	**59**	55	78
Total deferred exploratory well costs	**$ 363**	$ 339	$ 243
Number of projects with costs capitalized for greater than one year after completion of drilling	**2**	2	4

Exploratory well costs capitalized greater than one year after completion of drilling as of December 31, 2005 included $43 million for the Ozona prospect that was primarily incurred in 2001 and 2002 and $16 million for the Flathead prospect that was primarily incurred in 2001. Both prospects are located in the Gulf of Mexico. Marathon s plans are to develop the Ozona prospect as a subsea tieback to area infrastructure. Commercial terms have been secured for the tieback and processing of Ozona production and Marathon is attempting to secure a drilling rig to drill the development well. Technical evaluations on the Flathead prospect continued during 2005 and are progressing towards a potential re-entry and sidetrack well before 2008. In 2005, a well drilled on a block directly offsetting the Flathead prospect encountered hydrocarbons.

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	Other	Balance at End of Period
Year ended December 31, 2005	**$ 339**	**$ 135**	**$ (31)**	**$ (80)**	**$**	**$ 363**
Year ended December 31, 2004	243	239	(54)	(89)		339
Year ended December 31, 2003	148	256	(56)	(90)	(15) [(a)]	243

[(a)] Related to the sale of Marathon s exploration and production operations in Western Canada.

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15. Goodwill

The changes in the carrying amount of goodwill for the years ended December 31, 2005 and 2004, are as follows:

(In millions)	Exploration and Production	Refining, Marketing and Transportation	Total
Balance as of January 1 and 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**

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.

16. Intangible Assets