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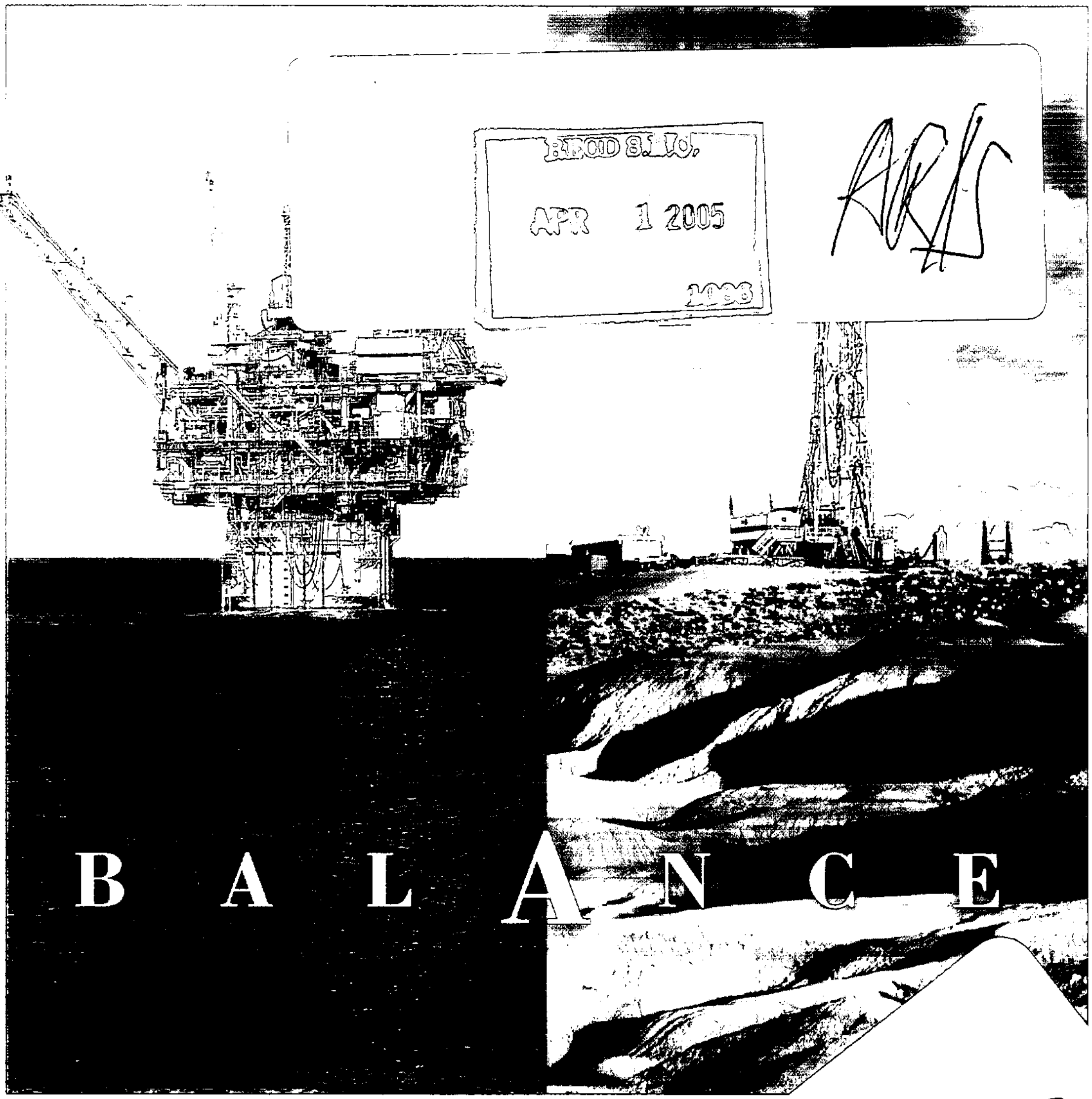


KERR-McGEE CORPORATION

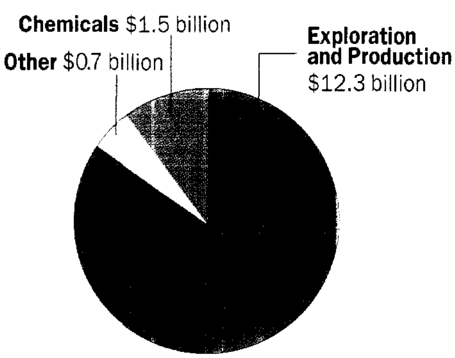
PROFILE

Kerr-McGee is an energy and chemical company with assets of more than $14 billion. The company is involved in two worldwide businesses: oil and gas exploration and production and the production and marketing of titanium dioxide pigment. With proved reserves of more than 1.2 billion barrels of oil equivalent, Kerr-McGee is one of the largest U.S.-based independent exploration and production companies. Its producing fields are located in the United States, the Gulf of Mexico, the United Kingdom sector of the North Sea and Bohai Bay, China. Kerr-McGee's chemical unit is the world's third-largest producer and marketer of titanium dioxide, an inorganic white pigment used in paint, coatings, plastics, paper and many other products. Founded in 1929, Kerr-McGee is based in Oklahoma City and has been listed on the New York Stock Exchange since 1956 under the symbol KMG.

KERR-McGEE CORPORATION

Financial Highlights

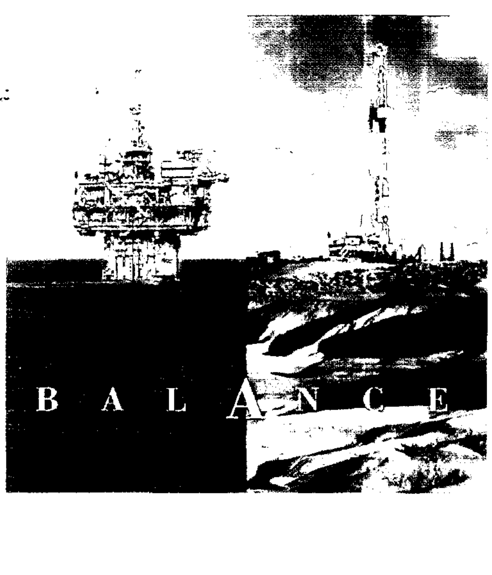
Millions of dollars, except per-share amounts	**2004**	2003	% Change
Revenues	**$ 5,157**	$ 4,080	26
Segment operating profit	**1,168**	966	21
Net income	**404**	219	84
Capital expenditures (including dry-hole costs)	**1,340**	1,162	15
Dividends paid	**205**	181	13
Total assets	**14,518**	10,250	42
Total debt	**3,699**	3,655	1
Stockholders' equity	**$ 5,318**	$ 2,636	102
Common shares outstanding at year end (thousands)	**151,889**	100,860	51
Per common share – diluted			
Net income	**$ 3.11**	$ 2.17	43
Stockholders' equity	**32.86**	23.79	38
Per common share			
Dividends declared	**1.80**	1.80	–
Market prices –			
High	**63.24**	48.59	30
Low	**46.92**	37.82	24
Year end	**57.79**	46.49	24



ASSETS AT YEAR-END 2004
$14.5 billion

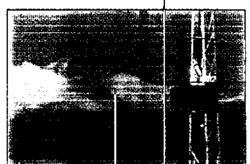
Operating Highlights

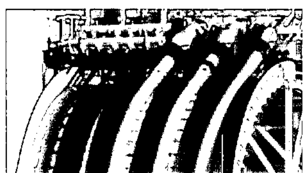
	2004	2003	% Change
Crude oil and condensate production (thousands of barrels per day)	**159**	150	6
Average realized price of crude oil sold (per barrel)	**$ 28.23**	$ 26.04	8
Natural gas sales (millions of cubic feet per day)	**921**	726	27
Average realized price of natural gas sold (per thousand cubic feet)	**$ 5.13**	$ 4.37	17
Titanium dioxide pigment production (thousands of tonnes)	**549**	532	3
Number of employees at year end	**4,084**	3,915	4

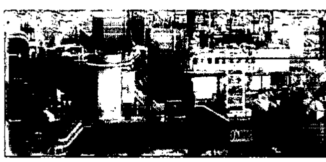


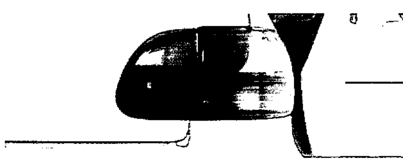
Balance

Success as an independent exploration and production company requires more than capital and expertise. It requires balance – maintaining the appropriate equilibrium between risk and reward, oil and gas, science and intuition. Kerr-McGee is committed to enhancing shareholder value through a balanced strategy that includes low-risk, high-margin exploitation activities and higher-risk, high-impact exploration opportunities. The company's titanium dioxide business also seeks balance in its production and marketing activities, providing global customers with high-quality products and services.



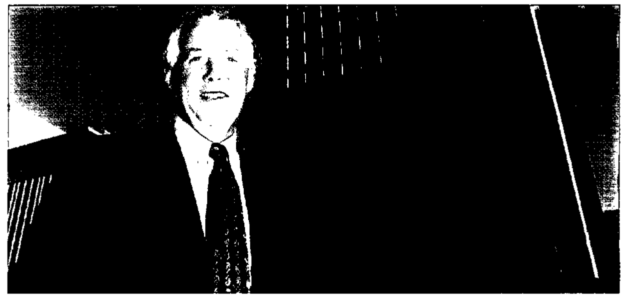






To our stockholders

Kerr-McGee today is a stronger, more balanced company than it was a year ago. Our 2004 successes added depth, breadth and balance to our company, positioning us to take advantage of future opportunities and enhancing shareholder value.



We are pleased to report that Kerr-McGee generated a total return to stockholders of 28.4% in 2004. At year end, production was at record levels, and we had increased reserves by nearly 20% to more than 1.2 billion barrels of oil equivalent (BOE). Both of these facts were complemented by rising commodity prices.

Kerr-McGee improved the balance of its oil and gas operations, increasing its inventory of repeatable, low-risk, high-margin exploitation opportunities, while concentrating our exploration program in proven hydrocarbon basins.

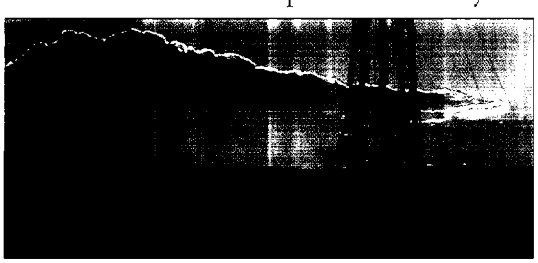
In 2004, we continued to implement our strategy to grow core areas where we have expertise, technological and cost advantages. During the past year, we:

- Replaced 280% of 2004 production and increased proved developed reserves to 65% of total reserves
- Balanced our portfolio with low-risk exploitation opportunities through the acquisition of Westport Resources Corp.
- Currently have more than 9,000 identified exploitation projects resulting from the Westport and prior HS Resources acquisitions
- Enhanced the balance of proved reserves to 57% natural gas and 43% oil, and 77% of proved reserves now are located in the United States
- Executed major development projects within budget and on or ahead of schedule
- Ended the year with record production of 372,000 BOE per day
- Generated $2.1 billion in operating cash flow
- Paid cash dividends of $1.80 per share in 2004, with a total stockholder return of 28.4%

In addition, we increased our financial strength and flexibility. In 2004, we continued to exercise financial discipline and operated within our cash flow. At the same time, we reduced the company's debt to capital ratio to 41% at Dec. 31, 2004, compared with 58% at the end of 2003.

Westport acquisition: adding opportunities

A highlight of 2004 was Kerr-McGee's acquisition of Westport, which was completed on June 25. The transaction increased our proved reserves by 281 million BOE and expanded our foundation of high-margin production and low-risk exploitation opportunities.



The long-lived, U.S.-based assets gained in the transaction have a probable and possible resource potential of 1.8 trillion cubic feet of natural gas equivalent. They include more than 2,500 identified, low-risk, proved undeveloped, probable and possible drilling locations.

The additional free cash flow created by the merger, combined with anticipated annual cost savings of more than $40 million, increases Kerr-McGee's financial flexibility.

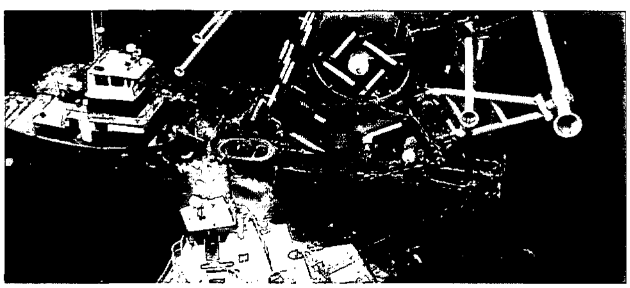
2004 oil and gas operations: achieving goals

The company's 2004 production increased by 15%, with daily production averaging 312,200 BOE. Record production was achieved in both the third and fourth quarters, in spite of an intense hurricane season in the Gulf of Mexico.

Kerr-McGee remains the largest U.S.-based independent oil and gas producer in the deepwater gulf. Currently, our net production in deep water is more than 80,000 BOE per day. This is the result of our proven success in deepwater gulf exploration, where the company leads its peer group, discovering approximately 800 million BOE of gross resources during the past five years.

The company achieved yet another industry milestone on July 15, 2004, when the Red Hawk field in the deepwater gulf began producing natural gas through the world's first cell spar, the newest facility in our fleet of five operated deepwater Gulf of Mexico production hubs.

Kerr-McGee's hub-and-spoke strategy continues to prove successful, with additional satellite wells brought on line at Boomvang and Neptune and the continuing ramp up of production at our Gunnison facility. Last year, we sanctioned two new hub developments in the deepwater gulf. The Constitution development will use a truss spar facility to process resources from the Constitution and Ticonderoga fields, with first production expected in mid-2006. Kerr-McGee also is joining five other companies in a project to develop multiple ultra-deepwater natural gas discoveries in the eastern Gulf of Mexico, where we operate the Merganser field and hold interests in two other anchor fields involved in the project, Vortex and San Jacinto.

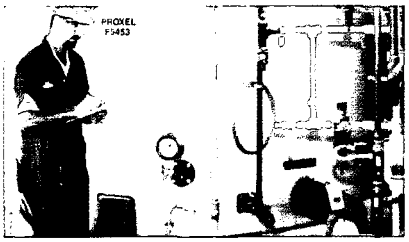


Three days after the Red Hawk startup, the company began producing oil through a floating production, storage and offloading facility from two fields in the Bohai Bay of China. First production was achieved five months ahead of schedule and marked the emergence of a new core area for Kerr-McGee. Keeping such large and complex projects within budget and on schedule requires flawless execution by all involved. Our oil and gas employees, partners and contractors put forth great efforts to make a challenging year successful, through the innovative use of advanced technology and outstanding teamwork.

During the year, Kerr-McGee enhanced its growth opportunities through drill-bit success, increased acreage positions and value-added transactions. Exploration successes included discoveries in the gulf, Alaska, Brazil, China, onshore United States and the U.K. sector of the North Sea. During 2004, Kerr-McGee increased its acreage positions in the Gulf of Mexico, Brazil and Alaska, which present new exploration opportunities in existing core areas as well as proven hydrocarbon basins. The company also has acquired 37.5% interest in the deepwater gulf Blind Faith discovery, which has estimated gross resources in excess of 100 million BOE. In the North Sea, Kerr-McGee increased its interest in the Gryphon field to 86.5%, and increased production through a successful four-well development program.

2004 chemical operations: pursuing excellence

As the world's third-largest producer and marketer of titanium dioxide pigment, our chemical business is well-positioned to capitalize on the improving market. After three years of depressed market conditions, the pigment industry began seeing visible signs of recovery last year. Stronger pigment demand supported higher prices.



Customer and market focus led to continued strengthening of our product performance and technical support team excellence. But we do not believe that the value of this business is fully reflected in our stock price.

2005 outlook: delivering value

For some time, Kerr-McGee's board of directors has been considering the separation of its chemical business, and current market conditions for the industry now make this an ideal time to unlock this value for our stockholders. The outlook for the chemical business is strong, with significant improvements in the inorganic chemical industry in general and Kerr-McGee's chemical operations in particular. Kerr-McGee's board is committed to building and delivering value to our stockholders through responsible, well-considered strategic actions. The board again demonstrated that commitment on March 8, 2005, when it voted to pursue alternatives for the separation of the chemical business. The board also authorized a $1 billion share repurchase program and expects to expand this program with the separation of the chemical business.

During its transition into a stand-alone business, the chemical unit will continue executing its strategy to increase margins, resulting in improved profits and cash flows. Upon completion of the chemical business separation, Kerr-McGee will become a pure oil and gas play, making the most of our well-balanced assets and focusing on our core competencies in exploration, exploitation, development and production to further enhance value for all stockholders.

2004 was a good year for our oil and gas operations, but we believe we can achieve even more. Our 2005 program is designed to seize many new opportunities and leverage our large prospect portfolio and talented, capable exploration and production teams.

We expect to achieve record production again in 2005, with volumes projected to increase in the range of 13% to 18%. We also expect further growth in production in 2006 from sanctioned projects currently under development. The company plans to grow reserves per share as we execute a strategic program that includes an increased percent of identified, low-risk exploitation opportunities in the Rockies and core U.S. onshore areas, appraisals of 2004 discoveries in Alaska, Brazil and China, and a high-potential exploratory program.

This year, we plan to drill more than 800 exploitation, appraisal and development wells and approximately 100 exploration wells. Through this process, we expect to move more of our large inventory of probable and possible resources into the proved reserve category throughout the year.

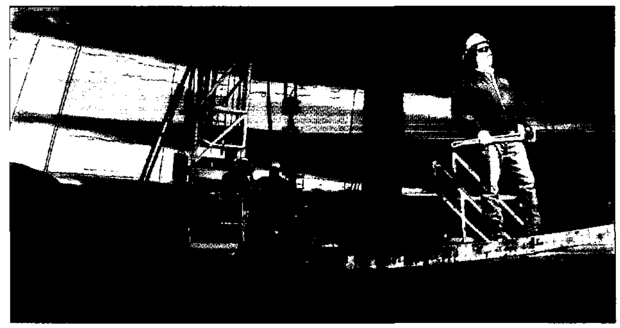
The company's 2005 exploration budget of $380 million will fund exploratory wells in core areas and new ventures such as offshore Alaska and Brazil. With a growing inventory of prospects, Kerr-McGee will drill the best of the best to create additional value for stockholders. Consistent with our strategy, we will continue to evaluate tactical transactions, seeking opportunities for per share growth and production stability.

Kerr-McGee has entered into commodity derivatives covering approximately 50% of its projected 2005 oil and gas production to underpin its capital program and to ensure a portion of the cash flow being used to finance our stock repurchase program, measures we believe are financially prudent. We remain firmly committed to maintaining an investment-grade credit rating.

Kerr-McGee: what we stand for

Kerr-McGee is committed to corporate responsibility, conducting our worldwide operations with integrity and complying with applicable laws wherever we operate. This commitment extends throughout the company. Our board of directors, officers and employees are expected to maintain high ethical standards in all dealings.

The safety of our employees, contractors and neighbors is of utmost importance. We strive to provide a safe workplace and have a wide range of programs in place to achieve this goal. As a result, the company's oil and gas and chemical units have safety incident rates less than half of the U.S. private industry rate.



In addition, we are committed to caring for the environment and our efforts have been recognized by communities, states and nations around the world. We also believe in supporting the communities where we operate. Our employees truly are some of the most caring, compassionate and giving people in the world, and I am proud of their contributions to improve the quality of life where we live, work and play.

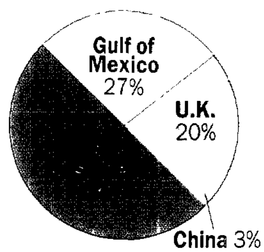
Last year, Kerr-McGee marked its 75th anniversary. It was a great pleasure for me to visit many of our operating units and share the celebration with Kerr-McGee employees around the world. We have a proud history and a bright future that we are approaching with confidence and vigor.

We ended 2004 a stronger and more balanced company, and we have in place all the elements required for sustaining growth: the right strategy, opportunities, and most importantly, people. I appreciate the continued contributions of Kerr-McGee's outstanding board of directors and employees. Together, we will work to help meet the world's energy needs, while increasing value for all stockholders.

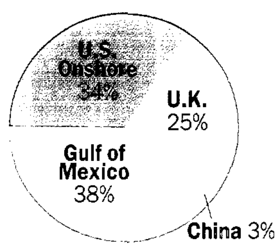
Luke R. Corbett
Chairman and
Chief Executive Officer
March 2005

Operations Overview

RESERVES AT YEAR-END 2004
1.2 billion BOE



RESERVES AT YEAR-END 2004
1.2 billion BOE



2004 OIL AND GAS PRODUCTION
114 million BOE

Opposite page: a rig drills in Utah's prolific Greater Natural Buttes area, where Kerr-McGee holds interests as a result of the Westport transaction.

Balancing opportunities

Kerr-McGee focuses its oil and gas operations on core areas that offer an appropriate balance of opportunities to execute key strategies that build shareholder value. In 2004, Kerr-McGee enhanced its balance by acquiring Westport Resources Corp., which added thousands of identified projects to the company's strong inventory of low-risk onshore exploitation opportunities. Production from the company's core operations in the U.S. onshore, the Gulf of Mexico, the North Sea and the Bohai Bay area of China provides a solid base of cash flow to underpin Kerr-McGee's high-potential exploration activities in the deepwater gulf and other proven hydrocarbon basins.

During 2004, Kerr-McGee started production at its Red Hawk field in the Gulf of Mexico, from the world's first cell spar. The company also achieved first production in its newest core area in the Bohai Bay area of China, within budget and five months ahead of schedule. In 2005, Kerr-McGee will take advantage of its balance, expertise and large portfolio of exploration and exploitation opportunities to successfully execute our exploration and production program. The company plans to continue to grow its oil and gas assets responsibly by ensuring its operations are conducted in a safe manner and with care for the environment.

Exploration and Production

(Millions of dollars, except per-unit amounts)	**2004**	2003
Revenues	**$3,855**	$2,923
Operating profit[1]	**$1,249**	$1,002
Net operating profit[1]	**$ 787**	$ 629
Crude oil and condensate production (thousands of barrels per day)	**159**	150
Average realized price of crude oil sold (per barrel)	**$28.23**	$26.04
Natural gas sales (millions of cubic feet per day)	**921**	726
Average realized price of natural gas sold (per thousand cubic feet)	**$ 5.13**	$ 4.37

[1]The 2004 operating profit includes $97 million in pretax charges ($62 million after taxes) related to losses associated with assets held for sale, asset impairments, nonhedge derivatives and other costs. The 2003 operating profit includes $3 million in pretax gains ($1 million after taxes) related to gains associated with assets held for sale, net of charges related to asset impairments, work force reduction provisions and other costs.

"Our strategy balances high-potential exploration, low-risk, repeatable exploitation and tactical acquisitions. Combined with our expertise and efficient execution, this strategy will provide the foundation for continued growth."

David A. Hager, Senior Vice President
Oil and Gas Exploration and Production

U.S. Onshore

KERR-McGEE'S MAJOR PRODUCING U.S. ONSHORE AREAS
(Kerr-McGee interest, location and average gross daily production in 2004)

☐ **Chambers County** (59.0%)
Texas
1,400 b/d, 16 MMcf/d

☐ **Flores/Jeffress** (80.0%)
Starr and Hidalgo counties, Texas
1,800 b/d, 28 MMcf/d

☐ **Greater Natural Buttes**[1] (82.0%)
Uintah County, Utah
700 b/d, 134 MMcf/d

☐ **Indian Basin** (50.0%)
Eddy County, New Mexico
400 b/d, 26 MMcf/d

☐ **Liberty County** (59.6%)
Texas
2,500 b/d, 54 MMcf/d

☐ **Moxa Arch**[1] (37.0%)
Lincoln, Sweetwater and Uinta counties, Wyoming
600 b/d, 61 MMcf/d

☐ **North Louisiana Complex** (22.0%)
Bienville and Webster parishes, Louisiana
600 b/d, 123 MMcf/d

☐ **Wattenberg** (94.0%)
Weld and Adams counties, Colorado
12,000 b/d, 182 MMcf/d

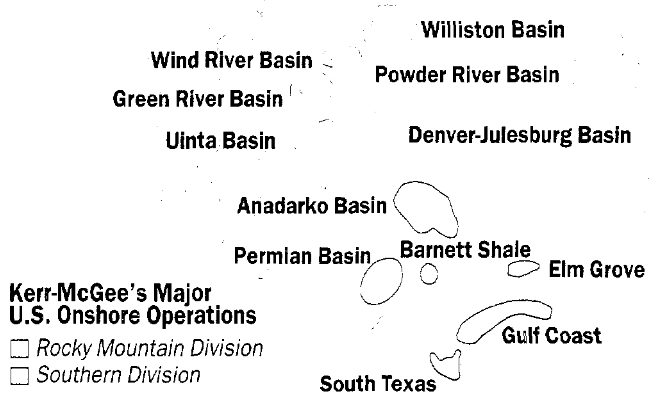
[1] Average daily production post Westport merger (June 25, 2004)
b/d: barrels of oil per day
MMcf/d: million cubic feet of gas per day
Kerr-McGee operates a significant number of these onshore assets.

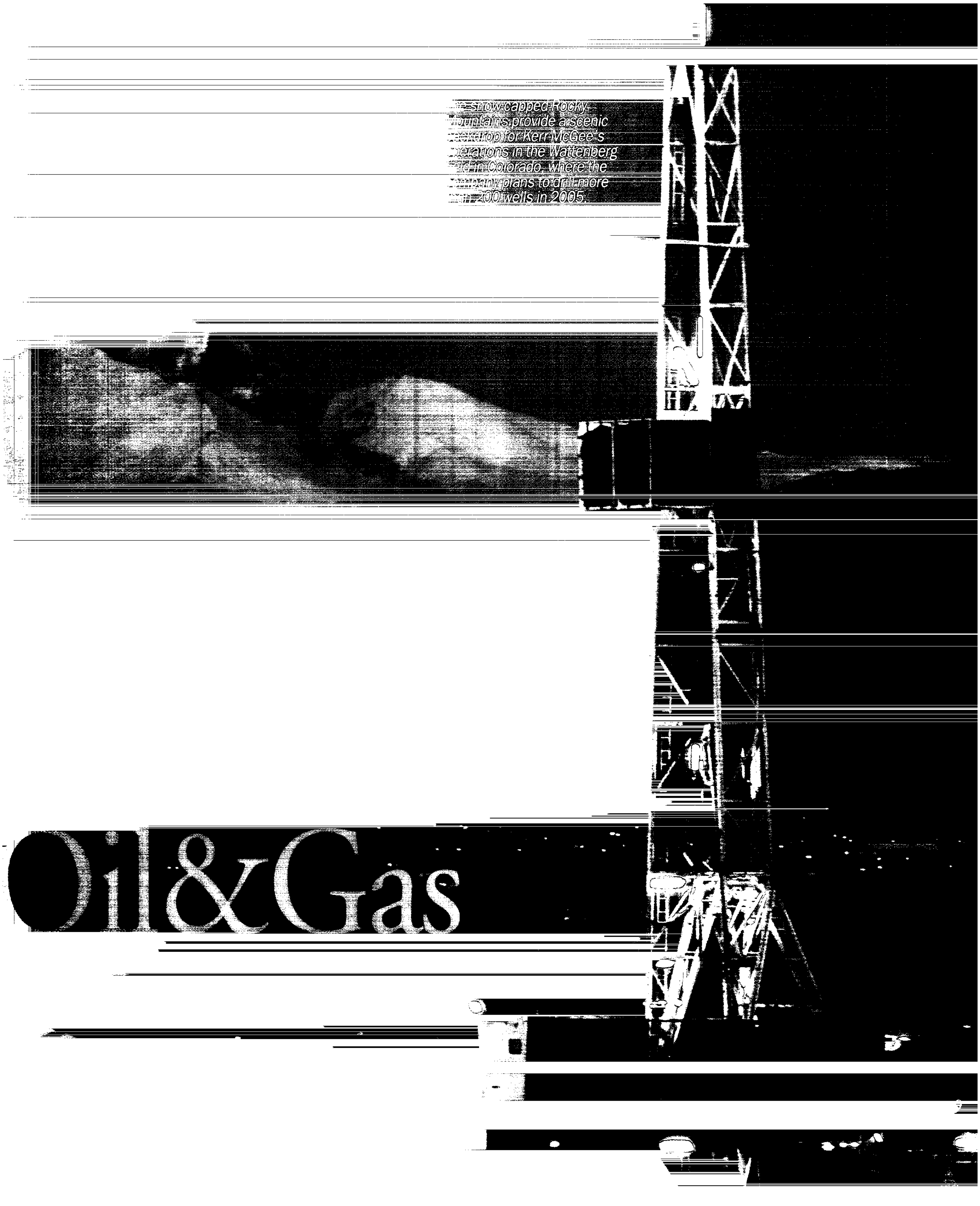
Kerr-McGee employees have the skill and expertise required to meet the challenge of drilling approximately 740 exploitation and development wells onshore in 2005.

Growing assets to meet growing demand

At year-end 2004, almost 67% of Kerr-McGee's natural gas reserves were located onshore in the United States, where the demand for natural gas continues to climb. The company's onshore operations include low-risk, repeatable exploitation plays that provide predictable, long-life volumes and strong cash flow to fund high-growth opportunities. Recognizing the significant potential for low-risk exploitation in the Rockies, the company holds dominant positions in the Wattenberg field of Colorado's Denver-Julesburg Basin and the Greater Natural Buttes area in Utah's Uinta Basin, with additional leaseholds in the Northern Rockies. Kerr-McGee also has a strong exploitation portfolio in the south Texas, upper Gulf Coast and mid-continent areas of the United States.

In 2004, the company increased reserves and identified additional projects in the Wattenberg field. Capitalizing on its tight-gas competencies, Kerr-McGee has grown its new assets in the Greater Natural Buttes area. The company will accelerate the development of its onshore inventory of more than 9,000 projects by drilling approximately 740 exploitation and development wells in 2005. Kerr-McGee will continue to leverage its experience and size as it expands its onshore project inventory and efficiently moves reserves from proved undeveloped and probable/possible resources to proved developed.





The snow-capped Rocky Mountains provide a scenic backdrop for Kerr-McGee's operations in the Wattenberg field in Colorado, where the company plans to drill more than 200 wells in 2005.

Oil&Gas

Gulf of Mexico

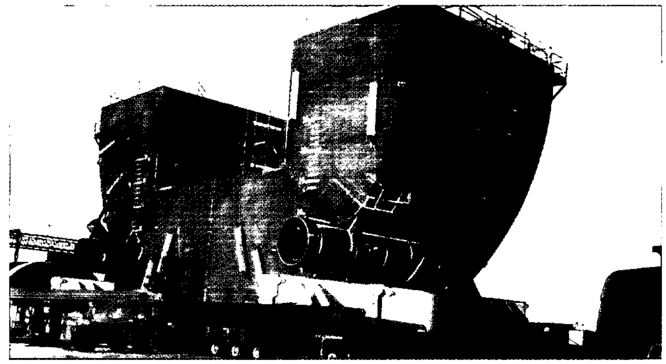
KERR-McGEE'S MAJOR PRODUCING GULF OF MEXICO FIELDS
(Kerr-McGee interest, location and average gross daily production in 2004)

- **Baldpate** (50.0%)
  Garden Banks 260 area
  14,100 b/d, 36 MMcf/d
- **Boomvang Area** (30.0%)*
  East Breaks 642, 643, 688, 598, 599
  30,500 b/d, 127 MMcf/d
- **Conger** (25.0%)
  Garden Banks 215
  28,000 b/d, 87 MMcf/d
- **Gunnison** (50.0%)*
  Garden Banks 667, 668, 669
  11,500 b/d, 119 MMcf/d
- **Nansen** (50.0%)*
  East Breaks 602, 646
  29,400 b/d, 147 MMcf/d
- **Navajo Area** (50.0%)*
  East Breaks 690, 646, 689
  4,300 b/d, 17 MMcf/d
- **Neptune** (50.0%)*
  Viosca Knoll 826 area
  10,800 b/d, 33 MMcf/d
- **Pompano** (25.0%)
  Viosca Knoll 989 area
  15,000 b/d, 24 MMcf/d
- **Red Hawk** (50.0%)*
  Garden Banks 877
  100 b/d, 53 MMcf/d
  (First production July 15, 2004)

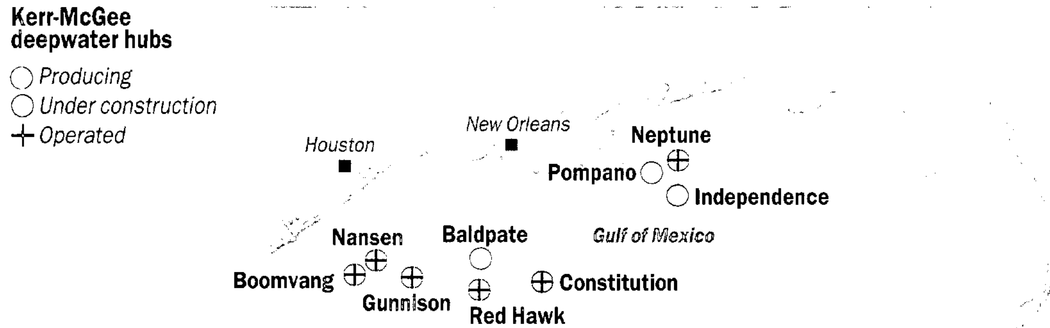
b/d: barrels of oil per day
MMcf/d: million cubic feet of gas per day
* *Operated by Kerr-McGee*

Hub-and-spoke strategy at work

Kerr-McGee marked another year of success in the Gulf of Mexico with production increasing 17% through continued growth in volumes from the deep water and the addition of Westport assets on the shelf. Kerr-McGee, the largest U.S.-based independent deepwater producer in the gulf, focuses its strategy on turning high-potential prospects and exploration success into economic returns by developing central processing facilities and tying back satellite fields. The hub-and-spoke strategy enhances the value of infrastructure investments and optimizes capacity utilization.



In 2004, Kerr-McGee started production from its fifth operated hub through the world's first cell spar at the Red Hawk field. Development began at its sixth operated deepwater hub, Constitution, with first production expected in mid-2006. The company's other hub-and-spoke systems continue to grow: Boomvang added three subsea wells, the Dawson Deep field is being developed as a tieback to Gunnison, and Neptune began production from the Nile field in early 2005. In 2004, Kerr-McGee discovered Ticonderoga, which will be tied back to Constitution. The company's discovery at San Jacinto expanded its presence in the eastern gulf, where it operates Merganser and holds interest in Vortex. These fields will be part of a development sanctioned by Kerr-McGee and five other companies. Interests in more than 870 blocks provide a strong prospect inventory, where the company will continue to balance growth through shelf exploitation, satellite opportunities around its growing infrastructure, high-potential new-field wildcats and tactical acquisitions.



Oil&Gas

Dwarfed by its size, tugboats tow the 560-foot-long Red Hawk cell spar hull more than 200 miles offshore. Red Hawk began production in July 2004. Opposite page: the Constitution truss spar currently is under construction in Pori, Finland.

United Kingdom

KERR-McGEE'S MAJOR PRODUCING NORTH SEA FIELDS
(Kerr-McGee interest, location and average gross daily production in 2004)

☐ **Brae area** (5% to 8%)
Blocks 16/2a, 16/3a, 16/3b, 16/3c, 16/7a, 16/7b
42,500 b/d, 425 MMcf/d

☐ **Buckland** (33.3%)
Block 9/18a
7,500 b/d, 9 MMcf/d

☐ **Gryphon** (86.5%)*
Blocks 9/18a, 9/18b, 9/23a
10,900 b/d

☐ **Harding** (30.0%)
Block 9/23b
38,600 b/d

☐ **Janice** (75.3%)*
Block 30/17a
11,400 b/d, 1 MMcf/d

☐ **Leadon** (100.0%)*
Blocks 9/14a, 9/14b
7,900 b/d

☐ **Maclure** (33.3%)
Block 9/19
9,800 b/d, 2 MMcf/d

☐ **Skene** (33.3%)
Block 9/19
5,100 b/d, 106 MMcf/d

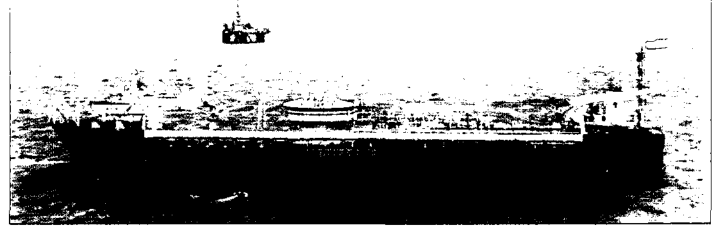
☐ **Tullich** (100.0%)*
Block 9/23a
8,500 b/d, 9 MMcf/d

☐ **Wytch Farm** (7.4%)
Licenses PL089, PL259; blocks 98/6, 98/7
37,300 b/d

b/d: barrels of oil per day
MMcf/d: million cubic feet of gas per day
* *Operated by Kerr-McGee*

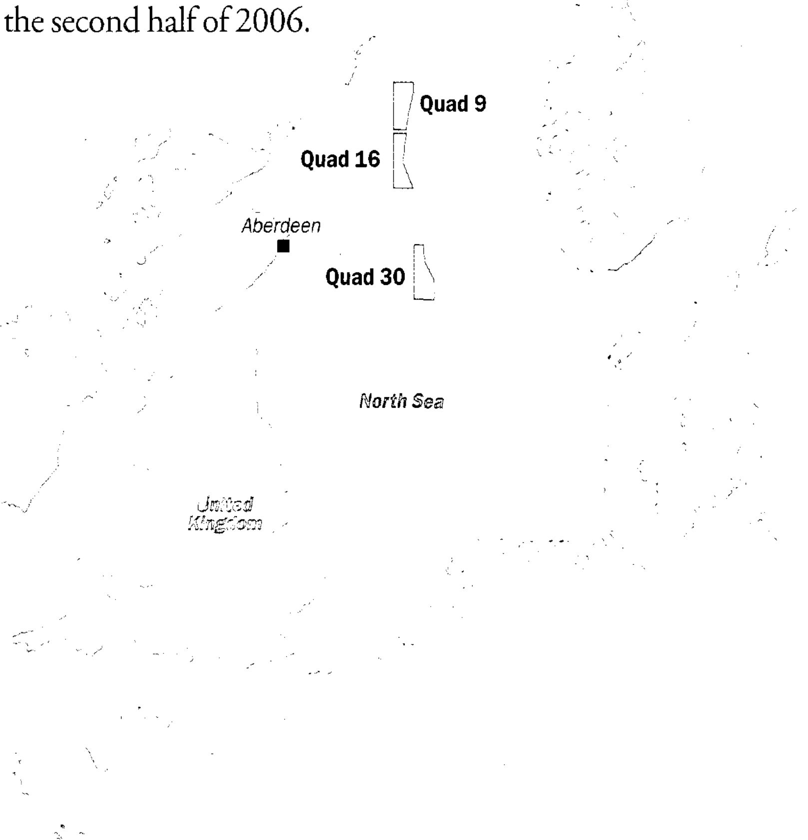
Exploitation and exploration in the North Sea

The United Kingdom sector of the North Sea has played an important role in the company's international oil and gas activities since 1976. The North Sea continues to support Kerr-McGee's success, and last year the area contributed 39% of Kerr-McGee's oil and condensate production. In 2004, the company took advantage of new opportunities to enhance its North Sea operations. The completion of four infill wells late in the year at the Gryphon field added 15,000 barrels of oil per day of gross production. In addition, a development well was completed in the James field, which at year-end 2004 produced more than 8,000 barrels of oil per day as a tieback to the company's Janice facility.



In 2005, Kerr-McGee will continue to exploit and explore the North Sea with three additional horizontal infill wells at the Gryphon field, targeting oil accumulations in injected reservoir sands. Exploitation activities also are planned at the Janice field. The company is reviewing development options for the Dumbarton and Affleck fields, with first production from Dumbarton expected in the second half of 2006.

Kerr-McGee has a strong position in the world-class central North Sea Basin, where a majority of its production comes from quadrants 9, 16 and 30.



Kerr-McGee continues exploitation activities in the United Kingdom sector of the North Sea, where in 2004, production at Janice was increased by a subsea tieback from the James field. Opposite page: Gryphon processed its 100 millionth barrel of oil in February 2004.

China

KERR-McGEE'S OPERATED LEASEHOLDS IN BOHAI BAY

PRODUCING FIELDS
☐ **Block 04/36**
(40.09% working interest)
CFD 11-1
CFD 11-2

UNDER DEVELOPMENT
☐ **Block 04/36**
(40.09% working interest)
CFD 11-3
CFD 11-5

First production expected second half 2005

DEVELOPMENT PLANNING UNDER WAY
☐ **Block 04/36**
(82% predevelopment foreign contractor's interest)
CFD 11-6

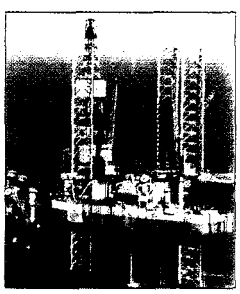
☐ **Block 05/36**
(50% predevelopment foreign contractor's interest)
CFD 12-1
CFD 12-1S

APPRAISALS UNDER WAY
☐ **Block 09/18**
(100% predevelopment foreign contractor's interest)
CFD 14-5

ADDITIONAL LEASEHOLD
☐ **Block 09/06**
(100% predevelopment foreign contractor's interest)

KERR-McGEE'S OPERATED LEASEHOLD IN THE SOUTH CHINA SEA

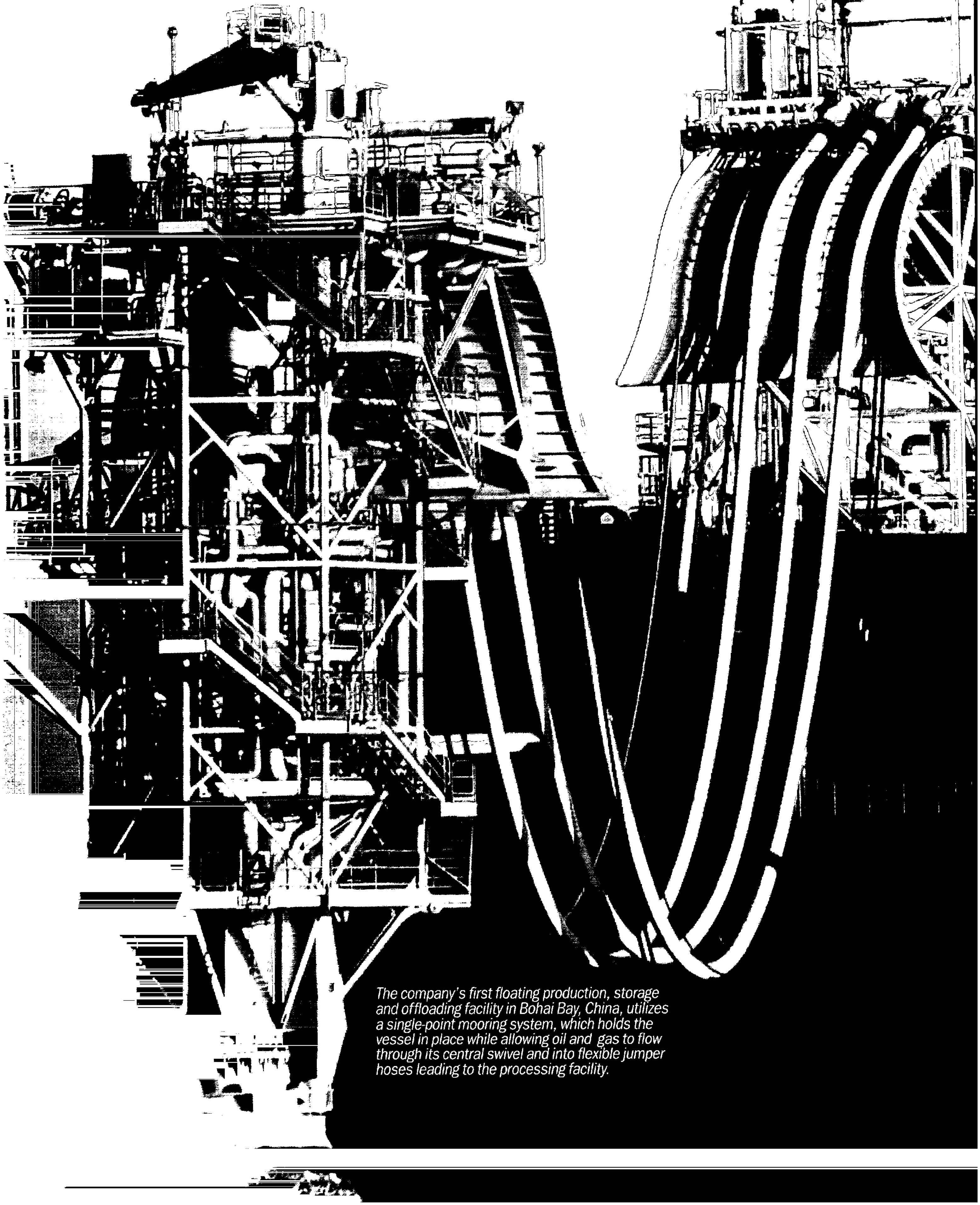
☐ **Block 43/11**
(100% predevelopment foreign contractor's interest)



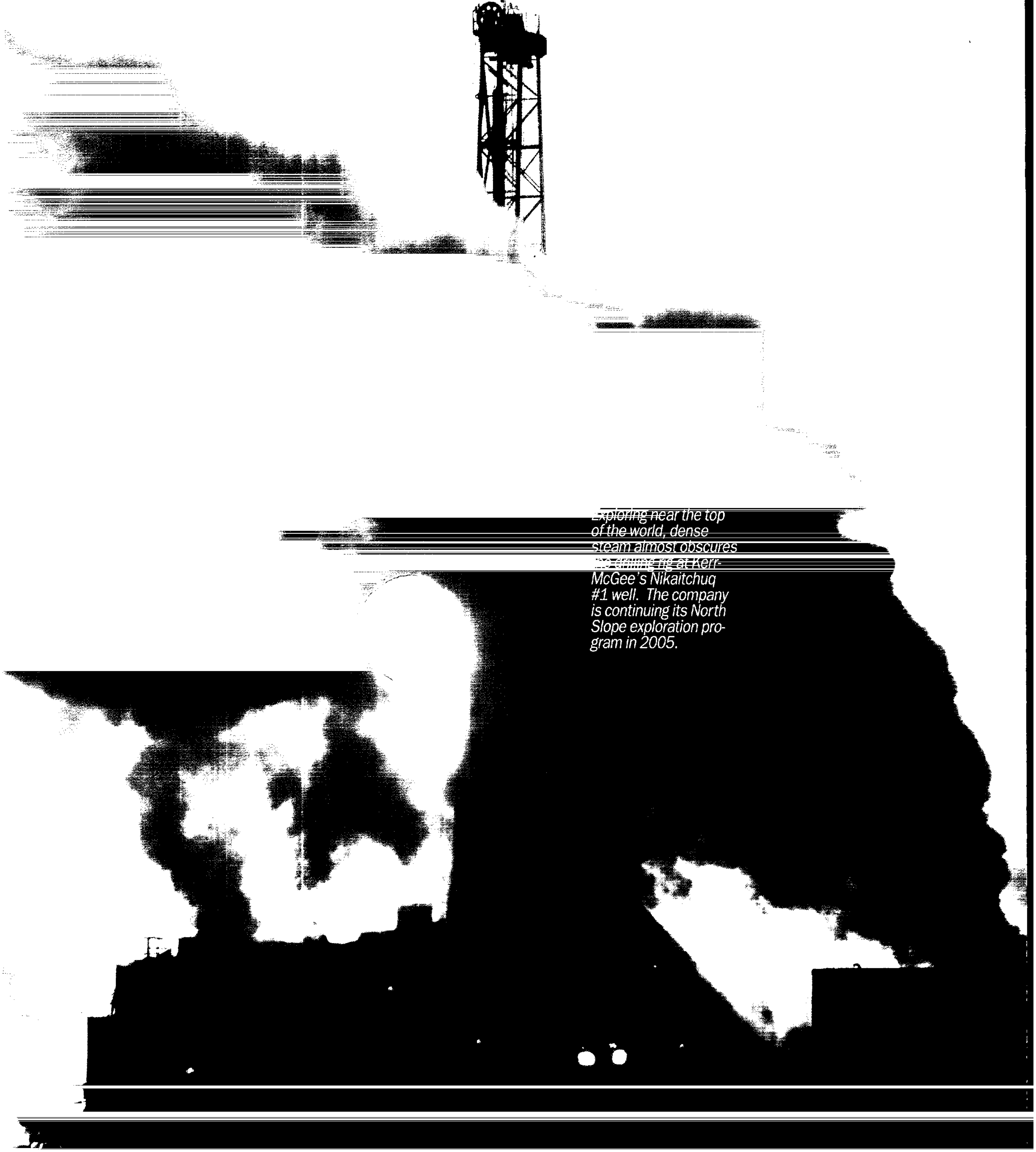
Developing a new core area

Production from Kerr-McGee's newest core area started in July 2004, when first oil flowed from the Cao Fei Dian (CFD) 11-1 and CFD 11-2 fields in block 04/36 in Bohai Bay, China. At year-end 2004, gross production ranged from 40,000 to 45,000 barrels per day, processing through the Hai Yang Shi You 112 – Kerr-McGee Global Producer VIII floating production, storage and offloading vessel. The company is developing two additional discoveries on block 04/36, which will extend the success of Kerr-McGee's hub-and-spoke strategy by using existing infrastructure. First production is anticipated in the second half of 2005. Development planning for three additional fields also is under way.

In 2004, Kerr-McGee made its eighth discovery in Bohai Bay, identifying a new reservoir about 20 miles southwest of the company's existing developments. This opens a new zone in a section of Bohai Bay where Kerr-McGee is adding prospects in its extensive acreage position. Early in 2005, Kerr-McGee and China National Offshore Oil Corporation (CNOOC) signed a production sharing contract for block 43/11, covering 2.4 million undeveloped acres in the South China Sea, in water depths from 5,000 to more than 10,000 feet. This contract more than doubles Kerr-McGee's China acreage and will allow the company to leverage its deepwater expertise and build on its long-standing relationship with CNOOC to explore for additional energy resources in China.



The company's first floating production, storage and offloading facility in Bohai Bay, China, utilizes a single-point mooring system, which holds the vessel in place while allowing oil and gas to flow through its central swivel and into flexible jumper hoses leading to the processing facility.



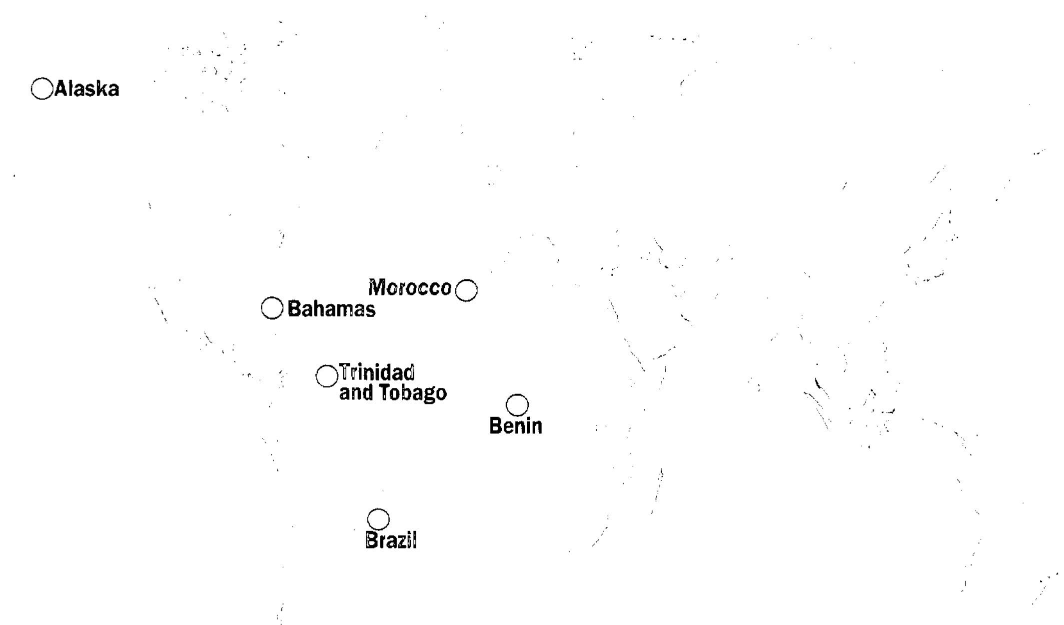
Exploring near the top of the world, dense steam almost obscures the drilling rig at Kerr-McGee's Nikaitchuq #1 well. The company is continuing its North Slope exploration program in 2005.

Targeting world-class prospects

Kerr-McGee's new ventures program focuses on high-potential prospects in proven hydrocarbon basins around the world. In 2004, the company had discoveries on the North Slope of Alaska and offshore Brazil. Alaska's North Slope is a promising area where the company has drilled two successful wells on the NW Milne Point prospect: the Nikaitchuq #1 discovery well and #2 appraisal well, which it operates with a 70% interest. Further appraisal operations began in the first quarter of 2005. Kerr-McGee drilled two additional exploratory prospects in the first quarter of 2005 and, based on its success, will continue its Alaska drilling program in winter 2005/2006.

Kerr-McGee's oil and gas team in the North Slope Basin of Alaska had a flawless safety record during 2004 exploratory drilling, despite much of its work being conducted outdoors in temperatures averaging minus 17 F (minus 27 C).

Offshore Brazil is another area that holds potential for Kerr-McGee. In 2004, the company was awarded an interest in seven new blocks in the prolific Brazilian, Campos and Espirito Santo Basins, where it is committed to a strong drilling program that includes eight wells during the next four years. Kerr-McGee expects to appraise its discovery on the BM-C-7 block in the Campos Basin during 2005. In addition, the company continues to enhance its prospect inventory through geological and geophysical work in these and other proven hydrocarbon basins around the world.



Titanium dioxide brightens and whitens a world of lifestyle products, including paints, coatings, plastics and paper, that consumers enjoy every day.

Pigment Chemicals

Pigment plants working toward a bright future

Kerr-McGee is the world's third-largest producer and marketer of titanium dioxide pigment, an inert, inorganic chemical used to brighten, whiten and opacify hundreds of everyday consumer products. Since 1998, the company has more than doubled its share of the global titanium dioxide market through low-cost, incremental expansions, and by acquiring strategically located production facilities that increase its ability to compete in all market segments on a worldwide basis. In 2004, technology-driven, low-cost plant improvements increased Kerr-McGee's gross chloride pigment production by 8%, allowing it to take advantage of the improving global market for titanium dioxide pigment.

The company pursued strategies in 2004 to enhance the value of its existing chemical assets and seize the opportunities presented by market momentum. These strategies include market and customer segmentation initiatives that focus on producing world-class products for high-growth, high-margin markets and on providing top-quality service to global customers. They emphasize the innovative use of technology and continuous improvement to enhance production capabilities, maintain high product quality and lower unit costs, while reducing the company's environmental footprint and minimizing waste. Kerr-McGee pigment plants in

KERR-McGEE PIGMENT PLANTS
(Annual gross capacity at year-end 2004)

CHLORIDE PROCESS

Hamilton, United States
225,000 tonnes

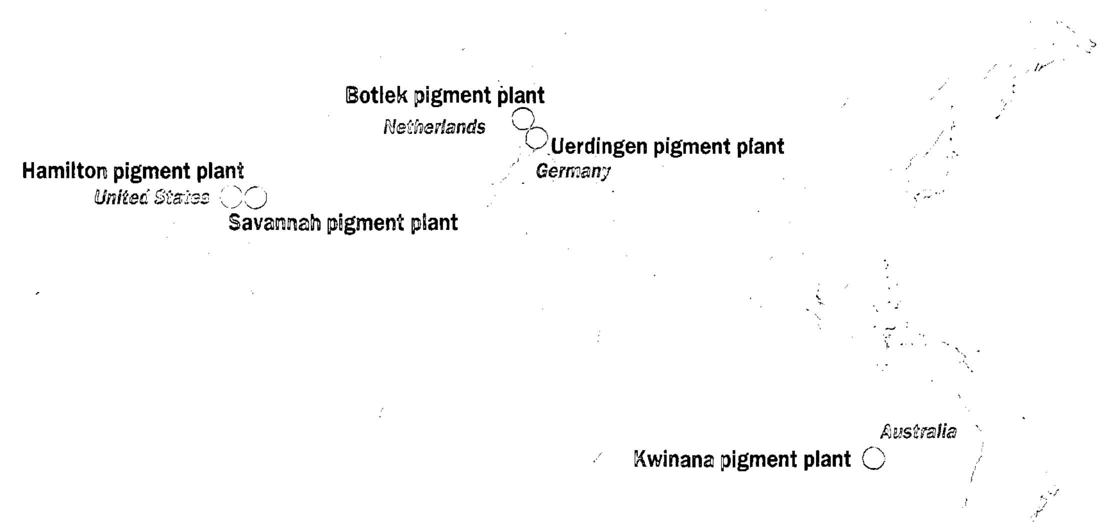
Savannah, United States
110,000 tonnes

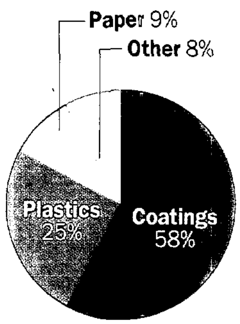
Botlek, Netherlands
72,000 tonnes

Kwinana, Australia
110,000 tonnes
(Tiwest Joint Venture – KM 50%)

SULFATE PROCESS

Uerdingen, Germany
107,000 tonnes

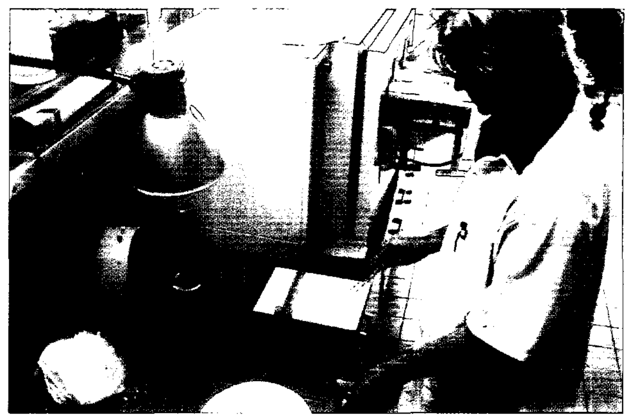




WORLDWIDE USES OF TiO_2 PIGMENT
4.6 million tonnes per year

Hamilton, Miss., U.S.; Savannah, Ga., U.S.; Botlek, the Netherlands; and a joint-venture plant in Kwinana, W.A., Australia produce pigment using the company's proprietary chloride process to meet the growing demand for chloride-process pigment in the paint, coatings and plastics markets.

In 2004, the company continued to evaluate $HiPO_2L$, a high-productivity technology that represents a potential step-change improvement in future operating and plant expansion costs. To enhance asset utilization and address the unacceptable financial performance of the Savannah sulfate facility, the sulfate plant was closed in 2004. This was a result of unanticipated environmental and infrastructure issues discovered after Kerr-McGee acquired the facility in 2000, and the deteriorating demand in the North American paper industry for sulfate pigments. The company's Uerdingen, Germany facility continues to produce the sulfate-process pigment preferred by European markets.



Chemical's high priority on safety resulted in a 2004 incident rate less than half the chemical industry average.

Early in 2005, the Kerr-McGee board of directors authorized management to proceed with its proposal to pursue alternatives for the separation of the chemical business including a spinoff or sale. The growth of the chemical unit over the past seven years has created the critical mass necessary for a viable stand-alone business. Current market conditions are ideal to capitalize on the quality and value of the chemical business, a value which is not fully reflected in the company's current market valuation.

The chemical business will continue to leverage its competitive advantages and the size and scope of its operations, and expects to continue to perform well and build value.

William E. Bradford, 70, Director since 1999; lead non-management director since 2003. Retired as Chairman of Halliburton Company, a provider of energy and energy services, in 2000; Chairman and Chief Executive Officer of Dresser Industries, Inc., now merged with Halliburton Company, from 1996 to 1998. Director, Valero Energy Corporation.

Luke R. Corbett, 58, Director since 1995. Chairman and Chief Executive Officer of the company since 1999 and from 1997 to 1999; Chief Executive Officer from February to May 1999; President and Chief Operating Officer from 1995 to 1997. Director, OGE Energy Corp. and Noble Corporation.

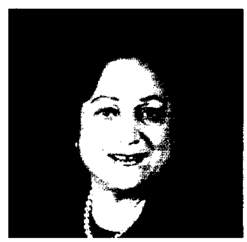
Sylvia A. Earle, 69, Director since 1999. Chair of Deep Ocean Exploration and Research, Inc., since 1992; Explorer-in-Residence for the National Geographic Society since 1998; and Program Director for the Harte Research Institute for Gulf of Mexico Studies, Texas A&M University - Corpus Christi, since 2001.

David C. Genever-Watling, 59, Director since 1999. President of GW Enterprises LLC, an investment and management firm, since 1998; Managing Director, SMG Management L.L.C., an investment firm, from 1997 to 2000. Previously President and Chief Executive Officer of General Electric Industrial and Power Systems.

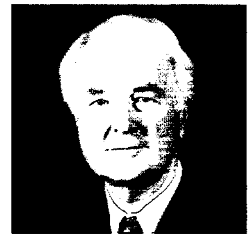
Martin C. Jischke, 63, Director since 1993. President of Purdue University since 2000; President of Iowa State University from 1991 to 2000. Director, Wabash National Corporation and Duke Realty Corporation.

Leroy C. Richie, 63, Director since 1998. Chairman and Chief Executive Officer of Q Standards World Wide, Inc., since 2000; Chairman and Chief Executive Officer of Capitol Coating Technologies, Inc., from 1999 to 2000; President of Intrepid World Communications from 1998 to 1999; Vice President and General Counsel for Automotive Legal Affairs, Chrysler Corporation, 1990 to 1997. Director, Infinity, Inc., and the companies in the Seligman family of investment companies, with the exception of Seligman Cash Management Fund, Inc.

William F. Wallace, 65, Director since June 2004, following the company's acquisition of Westport Resources Corp., where he served as a member of the Board of Directors since 2000. From 1995 to 1996, Director and Vice Chairman of Barrett Resources Corp., and from 1994 to 1995, President, Chief Operating Officer and Director of Plains Petroleum Co., which merged with Barrett Resources in 1995. Director, MarkWest Hydrocarbon, Inc.



Farah M. Walters, 60, Director since 1993. Retired as President and Chief Executive Officer of University Hospitals Health System, Cleveland, Ohio, in 2002. Director, PolyOne Corporation and Alpharma Inc.



Ian L. White-Thomson, 68, Director since 1999. Retired as Chairman of U.S. Borax, Inc., a provider of borax and borate products, in 1999; President and Chief Executive Officer from 1988 to 1999; Chief Executive Officer, Rio Tinto Borax Ltd., from 1995 to 1999. Executive Director of the Los Angeles Opera from 2000 to 2001.

Committees:

Audit

William E. Bradford
David C. Genever-Watling
Leroy C. Richie
William F. Wallace
Farah M. Walters
Ian L. White-Thomson

Executive Compensation

William E. Bradford
Sylvia A. Earle
David C. Genever-Watling
Martin C. Jischke
Leroy C. Richie
William F. Wallace
Farah M. Walters
Ian L. White-Thomson

Nominating and Corporate Governance

William E. Bradford
Sylvia A. Earle
David C. Genever-Watling
Martin C. Jischke
Leroy C. Richie
Farah M. Walters
Ian L. White-Thomson

March 2005

Corporate Officers

Luke R. Corbett, 58, Chairman and Chief Executive Officer since May 1999 and from 1997 to 1999; Chief Executive Officer from February to May 1999; President and Chief Operating Officer from 1995 to 1997. Joined Kerr-McGee in 1985.

Kenneth W. Crouch, 61, Executive Vice President since March 2003; Senior Vice President (oil and gas exploration and production) from 1998 to 2003; previously Senior Vice President responsible for oil and gas exploration. Joined the company in 1974.

David A. Hager, 48, Senior Vice President (oil and gas exploration and production) since 2003; Vice President of Exploration and Production from 2002 to 2003; Vice President of Gulf of Mexico and Worldwide Deepwater Exploration and Production from 2001 to 2002; Vice President of Worldwide Deepwater Exploration and Production from 2000 to 2001; Vice President of International Operations, 2000; previously Vice President of Gulf of Mexico operations. Joined Sun Oil Co., predecessor of Oryx Energy Company, in 1981. Oryx and Kerr-McGee merged in 1999.

Gregory F. Pilcher, 44, Senior Vice President, General Counsel and Corporate Secretary since 2000; Vice President, General Counsel and Corporate Secretary from 1999 to 2000; Deputy General Counsel for Business Transactions from 1998 to 1999; Associate/Assistant General Counsel for Litigation and Civil Proceedings from 1996 to 1998. Joined Kerr-McGee in 1992.

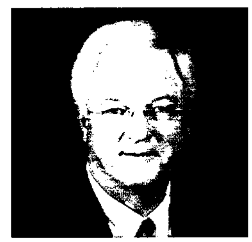
Robert M. Wohleber, 54, Senior Vice President and Chief Financial Officer since 1999. Previously held various positions at the Freeport-McMoRan group of companies, including Senior Vice President and Chief Financial Officer of Freeport-McMoRan Inc. and President, Chief Executive Officer and Director of Freeport-McMoRan Sulphur.

Thomas W. Adams, 44, Vice President of Chemical since September 2004; Vice President and General Manager of the Pigment Division from May to September 2004; Vice President of Strategic Planning and Business Development from 2003 to 2004; Vice President of Acquisitions from March 2003 to September 2003; Vice President of Information Management and Technology from 2002 to 2003. Joined Sun Oil Co., predecessor of Oryx Energy Company, in 1982. Oryx and Kerr-McGee merged in 1999.

George D. Christiansen, 60, Vice President, Safety and Environmental Affairs since 1998; Vice President of Environmental Assessment and Remediation from 1996 to 1998; previously Vice President of Minerals Exploration, Hydrology and Real Estate. Joined the company in 1968.

Fran G. Heartwell, 58, Vice President of Human Resources since 2003; Vice President of Human Resources, Kerr-McGee Worldwide Corporation, from January to March 2003; Director of Human Resources, Kerr-McGee Oil & Gas, from 2002 to 2003; Vice President of Human Resources and Administration, Oryx Energy Company, from 1995 until the 1999 merger of Oryx and Kerr-McGee.

Christina M. Poos, 35, Vice President and Treasurer since November 2004; Vice President and Treasurer for Kerr-McGee Worldwide Corporation from September to November 2004; Assistant Corporate Controller from February 2004 to September 2004; previously Director of Accounting, Food Brands America Incorporated (a division of IBP, Inc.) from 2000 to 2002. Joined Kerr-McGee in 2002.



John M. Rauh, 55, Vice President and Controller since 2002 and from 1987 to 1996; Vice President and Treasurer from 1996 to 2002. Joined the company in 1981.

John F. Reichenberger, 52, Vice President, Deputy General Counsel and Assistant Secretary since 2000; Assistant Secretary and Deputy General Counsel from 1999 to 2000; Deputy General Counsel from 1998 to 1999; previously Associate General Counsel for Remediation and Risk Management and Claims. Joined the company in 1985.

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, 2004

Commission file number 1-16619

KERR-MCGEE CORPORATION
(Exact name of registrant as specified in its charter)

DELAWARE	**73-1612389**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

KERR-MCGEE CENTER, OKLAHOMA CITY, OKLAHOMA 73125
(Address of principal executive offices)

Registrant's telephone number, including area code: (405) 270-1313

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

TITLE OF EACH CLASS	NAME OF EACH EXCHANGE ON WHICH REGISTERED
Common Stock $1 Par Value	New York Stock Exchange
Preferred Share Purchase Right	

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act).
Yes ☒ No ☐

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant was approximately $8.1 billion computed by reference to the price at which the common equity was last sold as of June 30, 2004, the last business day of the registrant's most recently completed second fiscal quarter.

The number of shares of common stock outstanding as of February 28, 2005, was 156,425,184. On March 2, 2005, an additional 6,798,333 shares were issued upon conversion of 5.25% debentures.

DOCUMENTS INCORPORATED BY REFERENCE

The definitive Proxy Statement for the 2005 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2004, is incorporated by reference in Part III of this Form 10-K.

PART I

Items 1. and 2. Business and Properties

GENERAL DEVELOPMENT OF BUSINESS

Through its predecessors, Kerr-McGee Corporation began operations in 1929 as a privately held company. In 1956 the company's stock began trading publicly on the New York Stock Exchange under the ticker symbol "KMG." Kerr-McGee's worldwide businesses and those of its subsidiaries are consolidated for financial reporting and disclosure purposes. Accordingly, the terms "Kerr-McGee," "the company," "we," "our" and similar terms are used interchangeably in this Form 10-K to refer to the consolidated group or to one or more of the companies that are part of the consolidated group.

Kerr-McGee is an energy and inorganic chemical holding company whose consolidated subsidiaries, joint ventures and other affiliates (together, "affiliates") have operations throughout the world. Our core businesses include:

- *Exploration and Production* - Kerr-McGee is one of the largest independent oil and gas exploration and production companies in the world, with major areas of operation onshore in the United States, in the Gulf of Mexico, the United Kingdom sector of the North Sea and China. In addition, we have strategic exploration programs in Alaska, Brazil, Morocco, Bahamas, and Benin. The company actively acquires leases and concessions and explores for, develops, produces and markets crude oil and natural gas.

- *Chemical* - Kerr-McGee affiliates engaged in chemical businesses produce and market inorganic industrial chemicals (primarily titanium dioxide pigment), lithium-metal-polymer batteries and heavy minerals. We are the world's third-largest producer and marketer of titanium dioxide pigment in terms of volumes produced.

The following table provides an overview of our operating performance and the composition of our assets and revenues by segment:

(Millions of dollars)	**2004**	2003	2002	2001	2000
Assets –					
Exploration and Production	**$12,246**	$ 7,385	$7,030	$ 8,076	$4,849
Chemical	**1,543**	1,734	1,655	1,631	1,638
Corporate and other	**729**	1,131	1,224	1,369	1,179
Total	**$14,518**	$10,250	$9,909	$11,076	$7,666
Revenues –					
Exploration and Production	**$ 3,855**	$ 2,923	$2,450	$ 2,428	$2,802
Chemical	**1,302**	1,157	1,065	1,023	1,153
Total	**$ 5,157**	$ 4,080	$3,515	$ 3,451	$3,955
Income (Loss) from Continuing Operations	**$ 415**	$ 264	$ (590)	$ 480	$ 812

Except for information or data specifically incorporated herein by reference under Items 10 through 14, other information and data appearing in the company's 2005 Proxy Statement are not deemed to be filed as part of this annual report on Form 10-K.

On June 25, 2004, we completed a merger with Westport Resources Corporation (Westport), an independent exploration and production company with operations onshore in the Rocky Mountain, Mid-Continent and Gulf coast areas in the U.S. and in the Gulf of Mexico. The merger added 281 million barrels of oil equivalent (boe) to our reserves, an increase of 27% from year-end 2003. In exchange for Westport's common stock and options, Kerr-McGee issued stock valued at $2.4 billion, options valued at $34 million and assumed debt of $1 billion, for a total of $3.5 billion (net of $43 million of cash acquired). The fair value assigned to assets acquired and goodwill totaled $4.7 billion. For a more detailed description of the Westport merger, see Note 2 to the Consolidated Financial Statements included in Item 8 of this annual report on Form 10-K.

On August 1, 2001, the company completed the acquisition of all the outstanding shares of common stock of HS Resources, Inc., an independent oil and gas exploration and production company with active projects in the Denver-Julesburg Basin, Gulf Coast, Mid-Continent and Northern Rocky Mountain regions of the U.S. Through this acquisition, we added approximately 217 million boe of proved reserves, primarily consisting of natural gas reserves in the Denver, Colorado, area, and expanded our low-risk exploitation drilling opportunities. The acquisition price totaled $1.8 billion in cash, company stock and assumption of debt. In connection with the HS Resources, Inc. acquisition, we completed a holding company reorganization in which Kerr-McGee Operating Corporation, formerly known as Kerr-McGee Corporation, changed its name and became a wholly owned subsidiary of the company. In this Form 10-K, filings and references to the company include business activity conducted by the current Kerr-McGee Corporation and the former Kerr-McGee Corporation before it reorganized as a subsidiary of the company and changed its name to Kerr-McGee Operating Corporation. At the end of 2002, another reorganization took place, whereby among other changes, Kerr-McGee Operating Corporation distributed its investment in certain subsidiaries (primarily the oil and gas operating subsidiaries) to a newly formed intermediate holding company, Kerr-McGee Worldwide Corporation. Kerr-McGee Operating Corporation formed a new subsidiary, Kerr-McGee Chemical Worldwide LLC, and merged into it.

In addition to a discussion of recent business developments provided below, reference is made to Management's Discussion and Analysis included in Item 7 of this annual report on Form 10-K, and the Exploration and Production Operations and Chemical Operations discussions below.

RECENT DEVELOPMENTS

Company to Pursue the Separation of its Chemical Business

The company announced on March 8, 2005, that its Board of Directors (the Board) authorized management to proceed with its proposal to pursue alternatives for the separation of the chemical business, including a spinoff or sale.

Share Repurchase Program

On March 8, 2005, the Board authorized the company to proceed with a share repurchase program initially set at $1 billion. The Board expects to expand the share repurchase program as the chemical business separation proceeds. The initial $1 billion share repurchase program primarily will be financed through the use of free cash flow generated from operations after planned capital expenditures, which is projected to be approximately $850 million in 2005. To ensure a portion of the projected cash flow, the company has entered into commodity derivative instruments covering approximately 50% of its projected oil and gas production. The company also expects to utilize a portion of its existing bank credit facility and may issue new securities, which may be in the form of debt or perpetual preferred stock, to fund the remaining repurchase program. The company still intends to retire $450 million of debt maturities due in 2005 in addition to the conversion of subordinated debentures discussed below. The Board and management reiterated their commitment to maintain an investment-grade credit rating.

The timing and final number of shares to be repurchased under an expanded repurchase program will depend on the outcome of the chemical business separation, as well as business and market conditions, applicable securities law limitations and other factors. Shares may be purchased from time to time in the open market or through privately negotiated transactions at prevailing prices, and the program may be suspended or discontinued at any time without prior notice.

Recommendation to Increase Authorized Stock

The company's Board of Directors in the March 8, 2005 meeting recommended for the stockholders to approve an increase of the authorized number of shares of the company's common stock, par value $1.00 share, from 300 million shares to 500 million shares.

Conversion of 5.25% Debentures

In February 2005, the company called for redemption all of the $600 million aggregate principal amount of its 5.25% convertible subordinated debentures due 2010 at a price of 102.625%. Prior to March 4, 2005, the redemption date, all of the debentures were converted by the holders into approximately 9.8 million shares of common stock. As a result of this conversion, the number of total common shares outstanding increased to approximately 162 million as of March 11, 2005. Pro forma for the conversion, the company's year-end 2004 total debt to total capitalization ratio would have been 34%.

SEGMENT AND GEOGRAPHIC INFORMATION

For financial information by operating segment and geographic information, see Note 27 to the Consolidated Financial Statements included in Item 8 of this annual report on Form 10-K.

EXPLORATION AND PRODUCTION OPERATIONS

Our exploration and production business is focused on achieving value-added growth through exploration, exploitation and acquisitions. The company's high-impact deepwater exploration efforts are balanced with lower risk exploration activities in proven world-class hydrocarbon basins in areas such as Brazil, Alaska, and China, as well as the U.S. onshore, Gulf of Mexico shelf and the North Sea. Through our strategic merger with Westport in 2004, we added complementary high-quality assets in core U.S. onshore and Gulf of Mexico regions. Combined with our existing U.S. assets, the Westport properties provide a stable foundation of high-margin production and low-risk growth opportunities, complementing our high-impact deepwater exploration program. The Westport acquisition added net proved reserves of 281 million boe, approximately two-thirds of which were natural gas reserves. Primarily as a result of this acquisition, natural gas reserves as a percentage of total proved reserves increased from 52% to 57% during 2004. Additionally, we increased proved developed reserves as a percentage of total proved reserves from 50% at December 31, 2003 to 65% by the end of 2004. This increase is attributable to both the Westport merger and to development investments made during the course of the year.

Strong crude oil and natural gas prices combined with record production during 2004 contributed to a 25% year-over-year increase in segment operating profit, which was $1.2 billion for 2004. The company's 2004 average daily production was 312,200 boe, a 15% increase from 2003. Natural gas production volume averaged 921 million cubic feet per day, an increase of 27% from 2003, and crude oil production volumes increased 6% in 2004 to 158,800 barrels per day. We ended 2004 with record fourth quarter production levels of 372,000 boe per day. The increase in production volumes during 2004 was largely attributable to the Westport merger. For 2005, we expect annual production to average between 352,000 and 367,000 boe per day.

Oil and Gas Sales Revenues, Volumes, Prices and Production Costs

The following table summarizes the company's crude oil and natural gas sales volumes and sales revenues from continuing operations for each of the three years in the period ended December 31, 2004. Sales revenues presented below include the impact of the company's hedging program. For information on the average realized sales prices including and excluding the effect of hedging arrangements, refer to Management's Discussion and Analysis of Financial Condition and Results of Operations - Segment Operations in Item 7 of this annual report on Form 10-K. Note 30 to the Consolidated Financial Statements included in Item 8 of this report presents the average lifting costs per boe.

(Millions)	**2004**	2003	2002
Crude oil and condensate (barrels)			
U.S. Gulf of Mexico	**21.9**	20.7	19.2
U.S. onshore	**10.3**	7.2	10.5
North Sea	**23.2**	26.1	37.2
China	**2.8**	0.8	1.2
Other international	**–**	–	1.4
	58.2	54.8	69.5
Crude oil and condensate sales revenues			
U.S. Gulf of Mexico	**$ 644.6**	$ 540.3	$ 414.8
U.S. onshore	**293.1**	188.1	224.8
North Sea	**613.7**	673.9	832.8
China	**92.2**	23.2	29.5
Other international	**–**	–	28.9
	$1,643.6	$1,425.5	$1,530.8
Natural gas (thousands of cubic feet)			
U.S. Gulf of Mexico	**133.1**	101.0	99.8
U.S. onshore	**172.6**	128.5	141.0
North Sea	**31.2**	35.4	36.7
	336.9	264.9	277.5
Natural gas sales revenues			
U.S. Gulf of Mexico	**$ 724.0**	$ 493.1	$ 322.2
U.S. onshore	**877.5**	553.8	410.5
North Sea	**127.0**	109.3	86.4
	$1,728.5	$1,156.2	$ 819.1

Reserves

Kerr-McGee's estimated crude oil, condensate, natural gas liquids and natural gas proved reserves at December 31, 2004, and the changes in net quantities of such reserves for the three years then ended are shown in Note 32 to the Consolidated Financial Statements included in Item 8 of this annual report on Form 10-K. Estimates of total proved reserves filed with or included in reports to any other Federal authority or agency during 2004, are within 5% of amounts shown in this filing.

Estimates of proved reserves and associated future net cash flows are made by the company's engineers and, for certain acquired Westport properties, third-party reserve engineers. In 2004, we engaged the independent reserve engineering firm of Netherland, Sewell & Associates, Inc. (NSAI) to review methods and procedures used by our engineers to estimate December 31, 2004 reserve quantities and future revenue for certain oil and gas properties located in the United States. For additional information with respect to NSAI's review and the company's methods and procedures employed in the reserve estimation process, see Note 32 to the Consolidated Financial Statements included in Item 8 of this annual report on Form 10-K.

Developed and Undeveloped Acreage

The following table summarizes the company's developed and undeveloped acreage held through leases, concessions, reconnaissance permits and other interests at December 31, 2004:

	Developed Acreage		Undeveloped Acreage	
Location	Gross	Net	Gross	Net
United States –				
Gulf of Mexico	933,499	381,632	3,604,879	2,097,040
Alaska	–	–	18,087	12,661
Onshore	2,903,532	1,752,601	2,337,695	1,256,934
	3,837,031	2,134,233	5,960,661	3,366,635
North Sea	363,403	121,378	792,495	392,286
China [(1)]	22,487	9,015	1,664,500	1,469,130
Other international –				
Morocco	–	–	30,245,687	13,973,805
Australia	–	–	10,031,824	6,129,398
Canada	–	–	2,087,220	1,310,826
Benin	–	–	2,459,439	1,721,607
Bahamas	–	–	6,488,680	6,488,680
Brazil	–	–	2,218,369	830,424
	–	–	53,531,219	30,454,740
Total	4,222,921	2,264,626	61,948,875	35,682,791

(1) Subsequent to December 31, 2004, Kerr-McGee signed a production sharing contract covering 2.4 million acres in the South China Sea with a 100% foreign contractor's interest in the first phase of the exploration period.

Gross and Net Productive Wells

The number of productive oil and gas wells in which the company had an interest at December 31, 2004, is shown in the following table. These wells include 1,888 gross or 857 net wells associated with improved recovery projects, and 2,584 gross or 2,472 net wells that have multiple completions but are included as single wells.

Location	Crude Oil	Natural Gas	Total
United States			
Gross	4,332	7,659	11,991
Net	2,880	4,495	7,375
North Sea			
Gross	274	5	279
Net	51	–	51
China			
Gross	31	–	31
Net	12	–	12
Total			
Gross	4,637	7,664	12,301
Net	2,943	4,495	7,438

Net Exploratory and Development Wells Drilled

Domestic and international exploratory and development wells that were completed as successful or dry holes during the three years ended December 31, 2004 are summarized in the following tables.

	Net Exploratory [1]			Net Development [1]			
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	Total
2004 [2]							
United States	13.6	9.5	23.1	412.7	7.5	420.2	443.3
North Sea	–	3.1	3.1	4.7	–	4.7	7.8
China	–	1.8	1.8	12.4	–	12.4	14.2
Other international	–	.9	.9	–	–	–	.9
Total	13.6	15.3	28.9	429.8	7.5	437.3	466.2
2003							
United States	6.7	11.0	17.7	241.6	1.0	242.6	260.3
North Sea	–	1.0	1.0	2.1	.1	2.2	3.2
Other international	–	5.0	5.0	.7	–	.7	5.7
Total	6.7	17.0	23.7	244.4	1.1	245.5	269.2
2002							
United States	4.8	11.1	15.9	186.9	1.4	188.3	204.2
North Sea	–	1.9	1.9	8.6	–	8.6	10.5
Other international	–	4.2	4.2	.8	–	.8	5.0
Total	4.8	17.2	22.0	196.3	1.4	197.7	219.7

(1) Net wells represent the company's fractional working interest in gross wells expressed as the equivalent number of full-interest wells.

(2) The 2004 net exploratory well count does not include 8.5 successful net wells drilled in the United States that are currently suspended, nor does it include 1.0 successful net well drilled in China, 1.6 successful net wells drilled in the North Sea, .3 successful net wells drilled internationally or 1.4 successful net wells drilled in the United States that will not be used for production.

Wells in Process of Drilling

The following table shows the number of wells in the process of drilling and the number of wells suspended or awaiting completion as of December 31, 2004:

	Wells in Process of Drilling		Wells Suspended or Awaiting Completion	
	Exploration	Development	Exploration	Development
United States				
Gross	4.0	19.0	33.0	33.0
Net	1.8	11.5	13.4	14.5
North Sea				
Gross	1.0	1.0	1.0	2.0
Net	.3	.1	.4	.2
China				
Gross	–	1.0	–	–
Net	–	.4	–	–
Total				
Gross	5.0	21.0	34.0	35.0
Net	2.1	12.0	13.8	14.7

Product Sales and Marketing

Our oil and natural gas production is sold at prevailing market prices, and the realized revenue on the physical sale is adjusted for net realized gains or losses on commodity derivative instruments designated to hedge sales of our oil and gas production. For further details on such derivative instruments, see the *Market Risks* section of Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this annual report on Form 10-K.

The company markets all of its crude oil, located primarily in the Gulf of Mexico, the U.K. North Sea and Bohai Bay, China, under a combination of term and spot contracts to refiners, marketers and end users under market-reflective prices. Our single-largest purchaser of crude oil during 2004 was BP PLC, accounting for 23% of total crude oil sales revenues and 9% of total natural gas sales revenues, or 17% of total crude oil and natural gas sales revenues. The creditworthiness of each successful bidder is reviewed prior to product delivery.

Our single-largest purchaser of domestic natural gas is Cinergy Marketing & Trading LLC, whose purchases are guaranteed by its parent company, Cinergy Corporation. Purchases by Cinergy represented approximately 48% of total gas sales revenues, or 23% of total crude oil and natural gas sales revenues in 2004. Kerr-McGee manages this significant single-customer exposure through a credit risk insurance policy.

The loss of any one customer is not expected to have a material effect on the company due to high demand for oil and natural gas.

Marketing of the company's domestic natural gas from the Wattenberg and Greater Natural Buttes fields, located in northeastern Colorado and northeastern Utah, respectively, is facilitated through its subsidiary, Kerr-McGee Energy Services Corporation (KMES). KMES is primarily engaged in the sale of the company's share of gas production. To fulfill its direct sales obligations and to fully utilize its contracted transportation capacity, KMES also purchases and markets natural gas from third parties. KMES sells natural gas to a number of customers in the Denver, Colorado, market, adjacent to the company's Wattenberg field. Natural gas production from the Wattenberg and Uinta fields, along with other Rocky Mountain fields acquired with the Westport merger, is sold at prevailing market prices.

North Sea natural gas is sold both under contract and through spot market sales in the geographic area of production.

Exploration and Development Activities

The following table shows a summary of key 2004 data for the company's operating areas. Production volumes are presented in thousands of barrels of oil equivalent per day (Mboe/d). Reserve volumes are stated in thousands of barrels of oil equivalent (Mboe). Additional information regarding oil and condensate and natural gas production, along with average prices received in 2004, 2003, and 2002 for the company's core geographic areas can be found in Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this annual report on Form 10-K.

	Estimated Proved Reserves at 12/31/04		2004 Production		Realized Sales Price Including Effect of Hedges	
	Mboe	Percentage of Total	Mboe/d	Percentage of Total	Oil $ per Barrel	Gas $ per Mcf
U.S. Gulf of Mexico	325,805	27%	120	38%	$29.43	$5.44
U.S. onshore	613,254	50	107	34	28.43	5.08
North Sea	242,355	20	77	25	26.50	4.06
China	36,686	3	8	3	32.37	–
Total	1,218,100	100%	312	100%	$28.23	$5.13

U.S. Gulf of Mexico

Kerr-McGee has been one of the pioneering exploration and production companies in the Gulf of Mexico since 1947, when we drilled the first successful well out of the sight of land. This tradition has continued with the pursuit of oil and gas farther offshore and in deeper water, where the company has developed a competitive advantage through the use of innovative and cost-effective technologies. Kerr-McGee was the first company to utilize floating production spar technology in the Gulf of Mexico in 1997 for its Neptune development. We continued to advance this technology through utilization of improved truss spar designs for our developments at the Nansen, Boomvang and Gunnison discoveries, which were sanctioned for development in 2000 and 2001. During 2004, first production was achieved at the Red Hawk development, where we used new cell spar technology, which lowers the threshold for economic development of deepwater reservoirs. The innovative design of the cell spar reduces the cost of construction and simplifies installation compared to other spar designs. Also in 2004, Kerr-McGee sanctioned both the Constitution discovery, where the company's fourth truss spar will be utilized, and the Independence Hub, a deep draft semi-submersible platform at a water depth of 8,000 feet. The nonoperated Independence Hub is being constructed by a consortium including Kerr-McGee and five other companies and is designed to process production from six fields including Kerr-McGee's Merganser, San Jacinto and Vortex fields.

Our merger with Westport led to increased production volumes and reserves in the Gulf of Mexico. However, because reserves added with the merger were primarily located in the U.S. onshore region, the weight of Gulf of Mexico proved reserves in our portfolio declined from 35% at year-end 2003 to 27% at year-end 2004. In 2004, Gulf of Mexico production represented 38% of the company's worldwide crude oil and condensate production and 39% of its natural gas production, largely unchanged from 2003. We expect that, in 2005, the Gulf of Mexico region will represent 27% of the company's total oil production and 39% of its natural gas production.

Kerr-McGee is one of the largest independent exploration and production companies operating in the Gulf of Mexico, with leases covering over 4.5 million gross acres. In 2004, the company maintained its position as one of the largest independent leaseholders in the deepwater Gulf of Mexico with approximately 530 deepwater blocks (deepwater locations are those in depths of more than 1,000 feet). We believe this extensive acreage holding provides a significant competitive advantage in our effort to maintain and develop a high-quality exploration prospect inventory.

Exploration Efforts

The Gulf of Mexico was again a focus of our exploration efforts in 2004. A total of fourteen deepwater exploratory wells were drilled or were drilling at the close of 2004. These wells included new field wildcats, satellites to existing infrastructure and appraisal wells to discoveries. In addition to the deepwater program, twelve exploratory wells were spud on the shelf of the Gulf of Mexico. Discoveries during 2004 included Ticonderoga (Green Canyon 768), Dawson Deep (Garden Banks 625), San Jacinto (DeSoto Canyon 618) and Nile (Viosca Knoll 869). Nile has been completed and will commence production in early 2005. Ticonderoga and San Jacinto have been sanctioned and design and equipment procurement are under way. Dawson Deep is anticipated to be sanctioned in 2005. Our exploration efforts on the Gulf of Mexico shelf were more active in 2004 compared to the prior year, which is the result of a focus on deep gas potential in a mature area, as well as properties entering the inventory through the Westport acquisition. The Westport inventory exposes Kerr-McGee to new trends and complements the existing portfolio.

To further enhance the exploration program, we entered into a joint venture with Stone Energy Corp. in the third quarter of 2004. This joint venture covers five to seven deepwater prospects, as well as several prospects on the Gulf of Mexico shelf. Drilling at the first of two deepwater wells in the joint venture package was ongoing at the end of the year and reached target depth in early 2005. The wells were declared unsuccessful in February 2005. Two additional exploration wells are planned for 2005.

At the close of the year, Kerr-McGee had contracted four deepwater drilling rigs for all or part of 2005, to facilitate execution of this part of the exploration program. Securing rig availability should allow the exploration pace to quicken and be maintained throughout 2005.

Development Activities

Our development activity in the deepwater Gulf of Mexico also continued at a high level during 2004 in terms of capital outlay, wells drilled and construction activity. Gunnison well completion activity continued throughout the year, gradually building the field's production rates. Installation of a cell spar was completed at Red Hawk and production began in July 2004. The Boomvang subsea production loop was completed, resulting in first production from the East Breaks 598 and 599 wells in the Boomvang field area.

Kerr-McGee also sanctioned participation in a joint project to develop several gas fields in the ultra deep waters (defined as greater than 8,000 feet) in the eastern Gulf of Mexico. The Independence Hub development will consist of a host processing and export facility to be located in Mississippi Canyon Block 920. This facility will receive production from six fields in the area through subsea tieback systems. We own an interest in three of these fields as follows: Merganser, Atwater Valley block 37 (50% - operator), Vortex, Atwater Valley block 261 (50%), and San Jacinto, Desoto Canyon block 618 (20%). The project is expected to be completed by year-end 2006, with first production anticipated in the second quarter of 2007. Kerr McGee's anticipated net production is over 100 million cubic feet of gas per day.

At the company's Constitution development, significant progress was made in 2004 on the truss spar construction. Development well drilling commenced in December 2004 and is expected to be completed in the second quarter of 2005. This Green Canyon (GC) block 679/680 discovery, which was approved for development in January 2004, is operated by Kerr-McGee with a 100% working interest. In addition, Kerr-McGee finalized plans for subsea tieback development of the Ticonderoga discovery (GC 768, 50% working interest) to the Constitution truss spar. Production from Constitution and Ticonderoga is expected to commence in the second quarter of 2006.

Deepwater Gulf of Mexico

Nansen field, East Breaks (EB) blocks 602 and 646 (50%): The Nansen field was sanctioned for development in March 2000, and first production was achieved in January 2002. Average 2004 gross production was 29,400 barrels of oil per day and 147 million cubic feet of gas per day. The Nansen field is developed with a truss spar in 3,700 feet of water and has nine dry-tree producers and three subsea wells tied back to the spar from a subsea cluster. Planned activity for 2005 includes the sidetracking of one subsea well and recompletion of three dry tree wells.

Navajo field, East Breaks block 690 area (50%): The Navajo field cluster is located on EB 646, 689 and 690. The Navajo discovery well, located in block 690, was drilled in September 2001. Following discovery, the well was completed and tied back to the Nansen spar located approximately five miles to the north. First production from Navajo was achieved in June 2002. Two previously drilled exploratory wells were completed and began production through the Navajo subsea system in 2003. A recompletion of one Navajo well is planned for 2005. Gross production from Navajo, West Navajo and Northwest Navajo wells averaged 17 million cubic feet of gas per day and 4,300 barrels of oil per day in 2004.

Boomvang field, East Breaks blocks 642, 643, 688 (30%), block 598 (50%) and block 599 (33%): The Boomvang field was sanctioned for development in July 2000 and first production was achieved in June 2002. The Boomvang field is developed with a truss spar in 3,450 feet of water and has five dry-tree producers and four subsea wells tied back to the spar from two subsea clusters. Two successful exploratory wells drilled on Kerr-McGee leases adjacent to the Boomvang field, EB 598 #1 and EB 599 #1, were tied back to the Boomvang spar during 2004. These two wells utilize a new subsea pipeline and cluster system. First production from both wells was achieved in October 2004. Average 2004 gross production from the Boomvang area was 30,500 barrels of oil per day and 127 million cubic feet of gas per day.

Gunnison field, Garden Banks block 668 area (50%): The Gunnison field, sanctioned for development in October 2001, incorporates a truss spar in 3,100 feet of water and has seven dry-tree wells and three subsea wells. First production from Gunnison started in 2003 from the three subsea wells, which produced approximately 3,600 barrels of oil per day and 125 million cubic feet of natural gas per day. During 2004, a completion rig was installed on the spar and completion operations began on the seven dry-tree wells. The final completion had to be sidetracked by the spar completion rig, but was placed on production in December 2004. Throughout 2004, oil rates were ramped up to a maximum of approximately 18,000 barrels of oil per day as wells were completed, and gas rates were maintained between 100 and 140 million cubic feet per day. Average gross production from Gunnison in 2004 was approximately 11,500 barrels of oil per day and 119 million cubic feet of gas per day.

Red Hawk field, Garden Banks block 877 (50%): Development of Red Hawk, a 2001 discovery, was sanctioned in July 2002, utilizing the world's first cell spar designed for developing smaller reservoirs in deepwater basins. Located in approximately 5,300 feet of water, the field has been developed using two subsea wells tied back to the cell spar. The two wells were completed during 2003 prior to installation of the spar. In 2004, the cell spar and production facilities were installed. The facilities were commissioned and first production began in July 2004. By the start of August, gross production had reached peak projected rates of 120 million cubic feet of gas per day. At year-end 2004, the field was producing approximately 128 million cubic feet of gas per day.

Neptune field, Viosca Knoll block 826 (50%): Production from the Neptune field began in March 1997 from the world's first floating production spar. Presently, there are 11 dry-tree wells producing through the facility at a water depth of 1,950 feet. Four subsea wells also produced to the spar in 2004, and the Nile exploratory well was drilled and completed in late 2004, with first production expected in 2005. Average 2004 gross production from Neptune was 10,800 barrels of oil per day and 33 million cubic feet of gas per day. Additionally, platform upgrades are being completed to accommodate Neptune's first third-party tieback, the Swordfish development, operated by Mariner. First production is planned for May 2005 and, along with Kerr-McGee's recent subsea tiebacks, is expected to increase gross Neptune gas production to the expanded platform capacity of 100 million cubic feet per day.

Conger field, Garden Banks block 215 (25%): Average 2004 gross production from the Conger field was 28,000 barrels of oil per day and 87 million cubic feet of gas per day. First production from the Conger field began in December 2000 from the first of three subsea wells. The three-well subsea development is the first multi-well, 15,000-psi subsea development and is located in approximately 1,500 feet of water. One additional well, a sidetrack of the Garden Banks 215 No. 6 well, was completed in December 2003. The Garden Banks 215 No. 8 well is anticipated to deplete its existing completion during 2005 and will be recompleted into a new zone, which is expected to increase production from this well.

Baldpate field, Garden Banks block 260 (50%): Average 2004 gross production from the Baldpate field, including the Penn State subsea satellite wells, was 14,100 barrels of oil per day and 36 million cubic feet of gas per day. The field is located in 1,690 feet of water and is producing from an articulated compliant tower. A successful exploration well was drilled and completed in late 2003 in Garden Banks 216 (Penn State) and was tied back to the existing Penn State subsea system.

Pompano field, Viosca Knoll block 989 area (25%): Average 2004 gross production from the Pompano field was 15,000 barrels of oil per day and 24 million cubic feet of gas per day. A platform rig was installed on Pompano during 2004 for a multi-well workover / recompletion program. Work on at least four wells is expected to be completed in the first half of 2005.

Gulf of Mexico Shelf

Production commenced in 2004 from several Gulf of Mexico shelf discoveries. Three wells were drilled at High Island 119 (42%), with initial gross production from two wells at 30 million cubic feet of gas. The third High Island 119 discovery began producing in January 2005. Three development wells and one exploratory well were drilled in the second half of 2004 at South Timbalier 41 (40%) with initial production of 15 million cubic feet of gas per day from the first well. First production from the remaining three wells, along with continued drilling in the field, is expected in 2005. In the fourth quarter of 2004, Garden Banks 208 (50%) began producing from a single subsea well at a gross rate of 15 million cubic feet of gas per day and Eugene Island 29 (45%) began producing at a gross rate of 5 million cubic feet of gas per day.

Development drilling took place in two fields in 2004. Two successful wells drilled at Main Pass 108 (75%) began producing at a gross rate of 15 million cubic feet of gas per day and two wells drilled in Ship Shoal 223 (32% to 45%) began producing at a gross rate of 5 million cubic feet of gas per day and 700 barrels of oil per day.

U.S. Onshore

In the U.S. onshore, exploration and production activities are segregated into two divisions, Rocky Mountain and Southern. Rocky Mountain operations are located in Colorado, North Dakota, Montana, Utah and Wyoming. Southern operations are primarily focused in Texas, Louisiana, Oklahoma, New Mexico and Kansas. In 2004, U.S. onshore production represented 51% of the company's worldwide gas production, 18% of its oil production and 50% of total year-end proved reserves. The weight of U.S. onshore proved reserves in our worldwide portfolio increased from 34% at the beginning of the year, largely as a result of our merger with Westport. We expect that in 2005, this region will represent approximately 55% of the company's total natural gas production and 20% of its oil production.

Rocky Mountain

Wattenberg field, Northeast Colorado (94%): Kerr-McGee obtained an interest in the Wattenberg field area as the result of the merger with HS Resources, Inc. in 2001. The Wattenberg gas field is located in the Denver-Julesburg (DJ) basin in northeast Colorado. Our 2004 net production from this field was 11,300 barrels of oil per day and 171 million cubic feet of gas per day. During 2004, the company completed more than 300 development projects in the field, including deepenings, fracture stimulations, recompletions and an aggressive infill drilling program. The drilling activities in 2004 were focused on the Codell Niobrara formations, with approximately half of the wells including additional depth to allow for future completion in the J Sand. As part of the infill drilling program, 49 5th spot wells (5th well in 160 acres) were drilled in the field to recover reserves that are not being drained with the current field spacing. Results from this program were economic and additional locations have been scheduled for future drilling. Codell refracture programs, as well as the operations to add the third fracture stimulation to existing Codell producers, continue to supply significant low-risk development opportunities.

In support of the ongoing DJ basin exploitation program, the company continued to successfully integrate the Wattenberg gathering system into its operating activities. During 2004, one new compressor was purchased and installed. Approximately 69,000 horsepower is currently being utilized to maintain system pressures for over 1,700 miles of gathering pipeline. Operation and management of the gathering system continues to provide improved reliability and reduced wellhead pressures system-wide. Kerr-McGee now operates more than 3,300 wells in the DJ basin, nearly 2,300 of which are connected to the Wattenberg gathering system. Company-operated production represents about 70% of the total system throughput of approximately 255 million cubic feet of natural gas per day, 30 million cubic feet of which is processed at the company's Ft. Lupton plant.

During 2004, we participated in sixteen exploratory wells in the Rocky Mountain area. Evaluation continued in the northeastern Colorado Niobrara play with the drilling of three additional wells, all of which were successful. The Niobrara prospect acreage and the eight wells drilled during 2003 and 2004 were sold in August 2004. Production was established at the Iron Horse, Marquis and Ocla Draw prospects in the Wind River basin. Kerr-McGee is participating in a Coalbed Methane (CBM) pilot in the Green River basin. In 2004, we drilled a second test well in our Gold Coast block to evaluate CBM potential. We also are participating in the delineation of a Frontier discovery in the Big Horn basin. Exploration drilling and evaluation of our position in the NE Red Desert will continue in 2005.

Greater Natural Buttes field, Uinta County, Utah (82%): Kerr-McGee obtained an interest in the Greater Natural Buttes field area in 2004 as the result of the the Westport merger. Kerr-McGee operates approximately 850 wells in the greater Natural Buttes field area and has interests in an additional 430 nonoperated wells. The combined estimated net production rates from this area at year-end 2004 were 500 barrels of oil per day and 117 million cubic feet of gas per day. The 2004 drilling program was primarily focused on exploitation of the Wasatch and Mesa Verde formations. During 2004, Kerr-McGee participated in 128 wells in our ongoing, multi-year development program.

In support of the production operations in Natural Buttes, Kerr-McGee operates over 770 miles of gas gathering pipeline and 19 gas compressors, totaling 20,000 horsepower. The system grew by 6,000 horsepower in 2004. The system has the capacity to deliver 230 million cubic feet of gas per day via multiple interstate pipeline systems, giving us the ability to service multiple markets. The gathering system will continue to grow in support of the field's aggressive development program, with at least 10 additional compressor installations planned for 2005. Total gross production gathered at year-end 2004 was 195 million cubic feet of gas per day.

Moxa Arch field, Southwest Wyoming (37%): Kerr-McGee obtained an interest in the Moxa Arch field area in 2004 as the result of the Westport merger. We now operate approximately 200 wells in the Moxa Arch field and have interests in 137 additional nonoperated wells. The combined estimated net production rates from this area at year-end 2004 were 300 barrels of oil per day and 27 million cubic feet of gas per day. The development program includes completions in both the Frontier and Dakota formations. During 2004, Kerr-McGee participated in 28 wells, including two wells that had initial production rates of 5 million cubic feet of gas per day in the Dakota formation. Development drilling is expected to continue in 2005.

Southern

The Southern division of our U.S. onshore operations had an active drilling program in 2004. We participated in 247 newly spud wells, of which 221 were development wells and 26 were exploratory wells. In 2004, we drilled 220 successful wells, and 13 wells were drilling at year-end, of which two are exploratory wells. The exploration program had a 77% success rate with twenty discoveries resulting in 2004, many of which have development follow-on potential.

Gulf Coast area: In the Gulf Coast area, a total of 41 wells were spud in 2004. The company plans to continue with an active drilling program in 2005, drilling over 50 wells in the Gulf Coast area. Kerr-McGee's two primary Gulf Coast areas of development are Chambers County, Texas, and Liberty County, Texas.

Chambers County, Texas - In Chambers County, five of six development wells drilled in 2004 were successful. Our share of 2004 production averaged 2,400 barrels of oil equivalent per day from Chambers County. We plan to drill over 10 wells in this area during 2005.

Liberty County, Texas - In 2004, Kerr-McGee expanded its Liberty County property base by drilling five development wells, all of which were successful, and 13 exploratory wells, 12 of which were successful. The company's net production rate at the end of 2004 was approximately 7,200 barrels of oil equivalent per day. We expect to drill over 10 wells in Liberty County in 2005.

South Texas area: In the South Texas area, a total of 56 wells were spud in 2004, including eight Wilcox, 21 Frio/Vicksburg, and 17 Lobo formation wells. Kerr-McGee plans to increase the drilling activity in 2005 by drilling in excess of 60 wells. Two areas of focus are:

Starr and Hidalgo counties, Texas - Kerr-McGee had an active drilling program in Starr County during 2004. Eighteen wells were spud, of which 17 resulted in new production. Average net production in 2004 from Starr and Hidalgo counties was 9,900 barrels of oil equivalent per day.

JC Martin field, Texas - The JC Martin field in Zapata County, Texas, produces from the Lobo formation at depths ranging from 8,500 to 10,000 feet. In 2004, we spud 11 development wells in the JC Martin field, 10 successful and one still drilling. This field produced an average of 2,300 net barrels of oil equivalent per day in 2004.

Mid-Continent/Permian area: In the Mid-Continent/Permian area, Kerr-McGee participated in 150 newly spud wells during 2004. At year-end, 122 of these new wells were producing, six were drilling and 19 were in the completion phase. This area covers production in New Mexico, west Texas, northern Louisiana, Oklahoma and Kansas. Two key locations within the Mid-Continent/Permian area for the company are North Louisiana and Indian Basin, New Mexico.

North Louisiana - The company owns an interest in the Elm Grove field and in the North Louisiana Field Complex, which is comprised of four adjacent fields. In 2004, Kerr-McGee maintained an aggressive development drilling program in the area, where 87 wells were drilled, 85 of which were successful, with two drilling at year-end. The company's current net production for this area is approximately 5,000 barrels of oil equivalent per day. Kerr-McGee expects to drill over 70 wells in this area in 2005.

Indian Basin, New Mexico - This shallow decline area offers steady production to the Kerr-McGee portfolio. Four wells were drilled and brought online in 2004. Net production from Indian Basin averaged 2,300 barrels of oil equivalent per day in 2004.

North Sea

Kerr-McGee has been active in the North Sea area since 1976. As of December 31, 2004, Kerr-McGee had interests in 20 producing fields in the United Kingdom sector. In 2004, North Sea production represented 39% of the company's worldwide crude oil and condensate production and 9% of its gas production. The North Sea area represents about 20% of Kerr-McGee's total worldwide proved reserves. In 2004, the weight of the North Sea production and proved reserves in our worldwide portfolio declined due to our merger with Westport, which increased our reserve base in the U.S. We expect that in 2005 approximately 40% of the company's total oil production and 6% of gas production will come from the North Sea area.

During 2004, the company launched a six-well North Sea exploration and appraisal program with the drilling of five operated wells and one nonoperated well. Of these six wells, four wells were dry and two wells were successful. One of these successful wells was the Dumbarton field appraisal well 15/20b-15, completed in November, which proved the southern area of the field. The Dumbarton field, Block 15/20, was acquired as part of the North Sea fallow block program. The field is currently under evaluation for development options either as a subsea tieback to existing nonoperated infrastructure or as a stand alone facility.

Business development initiatives during 2004 to strengthen the North Sea core area included acquiring 50% interest in license 29/20a and 11% in 30/2a shallow. In addition, a fallow block agreement was reached resulting in the acquisition of 66% interest and operatorship of block 22/25a, 50% interest and operatorship of blocks 23/26a (South), 30/1a and 30/1e, and 65% nonoperated interest in block 22/15. We also acquired 100% interest in block 16/21d and equalized our interest in blocks 9/15b and 9/15a (both are now at 86.32%). Certain of these acquired blocks contain known hydrocarbon discoveries, which the company believes may have future appraisal or development potential.

The following is a summary of the company's five key developments in the North Sea area, with identification of Kerr-McGee's working interest. These developments contributed approximately 77% of total net North Sea production during 2004.

Gryphon area, blocks 9/18a, 9/18b, 9/19 and 9/23a (Maclure field 33.3%, Gryphon field 86.5%, South Gryphon field 89.9% and Tullich field 100%): Average 2004 gross production from the Gryphon area was 29,200 barrels of oil per day and 10.7 million cubic feet of gas per day. The Maclure and Tullich subsea satellites began production in August 2002. In 2003, we acquired an additional 25% interest in the Gryphon area. This area is produced into a floating production, storage and offloading (FPSO) vessel, with oil exported via shuttle tanker. Gas is exported to the Leadon facility for fuel usage and/or sold on the spot market via the St. Fergus terminal.

Janice area, block 30/17a (75.3%): Average 2004 gross production from the Janice field was 11,400 barrels of oil per day and 1.2 million cubic feet of gas per day. During 2004, production began from the James field, part of the Janice area. Kerr-McGee operates James and Janice with a 75.3% interest. Oil from James is produced from a single well as a subsea tieback to the Janice 'A' floating production facility. First oil production from James occurred in November 2004 with sustained flow rates of approximately 8,000 barrels of oil equivalent per day.

Leadon field, block 9/14a and 9/14b (100%): Average 2004 gross production from the Leadon field was 7,900 barrels of oil per day. The Leadon field is being produced into an FPSO vessel, and the oil is exported via shuttle tanker.

Harding field, block 9/23b (30%): Average 2004 gross production from the Harding field was 38,600 barrels of oil per day. The Harding field provides Kerr-McGee with additional infrastructure in the strategically important quadrant 9 area of the North Sea. Within the same quadrant, Kerr-McGee also has interests in Gryphon, Leadon, Buckland, Skene, Maclure, and Tullich.

Skene field, block 9/19 (33.3%): The Skene field began producing in December 2001. Average 2004 gross field production was 106 million cubic feet of gas per day and 5,100 barrels of oil per day. The Skene field is being produced through a subsea tieback to the Beryl Alpha platform. The oil is exported via shuttle tanker, while the gas is exported via pipeline to the St. Fergus terminal.

China

During 2004, China's Bohai Bay became a core operating area for Kerr-McGee, with a total of eight discoveries made since the company first became involved in the area. In 2004, production in China represented 3% of the company's worldwide oil and gas production. We expect this area will contribute over 10% of the company's total 2005 oil production. In early 2005, we entered into a production sharing contract with China National Offshore Oil Corp. (CNOOC) for block 43/11, which covers 2.4 million acres in the deepwater South China Sea. We hold a 100% foreign contractor's interest in the first phase of the exploration period. CNOOC has the right to participate with up to a 51% interest if Kerr-McGee enters into the development phase.

Bohai Bay block 04/36 (81.8% working interest in exploration and 40.09% in development and production phases): Kerr-McGee commenced first production from the CFD 11-1 and 11-2 oil fields in July 2004. Two platform topsides were installed and the FPSO was built in China's port city of Dalian and then mobilized to the field in May 2004. Development drilling continued throughout the year at the CFD 11-1 field, and the development drilling program was completed at the 11-2 field. Thirty-six wells were completed and placed on either production or injection by the end of 2004. Gross production for 2004 was 15,100 barrels of oil equivalent per day (annualized), with year-end rates at 41,000 barrels of oil equivalent per day.

Oil in Place (OIP) reports for the CFD 11-3/11-5 fields were approved by the Chinese government in June 2004. CNOOC approved the Overall Development Plan for these fields in March 2005. Government approval is expected in the second quarter of 2005. The development plan centers on a tieback to the CFD 11-1 and 11-2 facilities with full processing of the fluids at the FPSO. Export will be commingled with similar quality crude from the CFD 11-1 and 11-2 fields. The development plan is based on four wells initially being drilled. First production is anticipated in the fourth quarter of 2005.

The CFD 11-1N-1 exploration well was drilled in 2004 to the north of the CFD 11-1 development area, but was declared unsuccessful.

Bohai Bay block 05/36 (50% working interest in exploration phase): Two appraisal wells were successfully drilled in the CFD 12-1 and 12-1S fields during 2003. The OIP reports for the CFD 12-1 and 12-1S fields in block 05/36, along with CFD 11-6 field in block 04/36, were approved in December 2004. The development plan for these fields is in the final stages of the approval process with CNOOC and new prospects for block 05/36 are being evaluated for drilling in 2005. In addition, CNOOC has approved a one-year extension which would provide for a new permit expiration date of February 28, 2006, subject to government approval. There will be a one-well obligation resulting from this extension and Shahejie play leads are being developed in preparation for this extension.

Bohai Bay block 09/18 (100% working interest in exploration phase): Two exploration commitment wells were drilled in this area in 2004, the CFD 14-5-1 and CFD 23-3-1. CFD 14-5-1 was an oil discovery in Eocene Shahejie sands. An appraisal program for the area is planned for 2005. The CFD 23-3-1 was declared unsuccessful. CNOOC has approved a one-year extension for the exploration phase, subject to government approval, whereby all 550,000 acres will be retained until the next election point on November 1, 2005.

Bohai Bay block 09/06 (100% working interest in exploration phase): The company signed an exploration contract in August 2003 for this 440,000-acre block in Bohai Bay, adjacent to the other concessions operated by Kerr-McGee. Since the 2004 CFD 14-5-1 discovery well was in the deep Shahejie formation, the appraisal will extend into block 09/06. Drilling will occur in 2005. The company purchased 3-D seismic data to help define prospectivity of the area.

Alaska

Kerr-McGee signed a participation agreement with Armstrong Oil and Gas (Armstrong) on December 24, 2003, to jointly explore areas of the prolific Alaska North Slope. Kerr-McGee acquired a 70% working interest in and operates nine leases totaling approximately 18,000 acres off the Alaska coast, northwest of Prudhoe Bay. The agreement includes the right to acquire an interest in 14 additional leases in the area, totaling 52,000 acres. In the October 2004 State of Alaska lease sale, Kerr-McGee and Armstrong were high bidders on four adjacent tracks with 5,120 available acres. In 2004, the company drilled a successful exploration and appraisal well on the NW Milne Point prospect (Nikaitchuq). An appraisal and testing program of the Nikaitchuq discovery is currently under way and two additional exploration wells are drilling.

Other International

Australia

WA 34-R (Formerly WA 278P) (39%): In 2004, a retention lease was granted by the Australian government for the areas around Kerr-McGee's Prometheus and Rubicon wells. These wells, drilled in 2000, successfully encountered natural gas but were considered noncommercial. We sold our interest in October 2004 and have no further obligations.

WA 301, 302, 303, 304 and 305 (50%): Kerr-McGee has an interest in 6.4 million acres in the deepwater Browse basin. The first exploratory well, Maginnis, was drilled in early 2003 and was unsuccessful. Kerr-McGee has entered into phase two of exploration. Geologic studies are planned in 2005 for blocks 303, 304 and 305. We have withdrawn from blocks 301 and 302 and have no further interest in the area.

WA 337 (100%) and WA 339 (50%): In early 2003, Kerr-McGee acquired an interest in 2.3 million acres in the deepwater Perth basin. Seismic data was acquired in late 2003, and processing is now complete. The remaining obligation for these blocks includes geologic studies, which are planned for 2005.

EPP 33 (100%): In late 2003, Kerr-McGee was awarded an interest in 1.3 million acres in the deepwater Otway basin. A new 2-D seismic survey over the block was acquired in the fourth quarter of 2004. Processing of the seismic data is currently under way.

Bahamas

On June 25, 2003, Kerr-McGee signed an exploration contract (100%) on 6.5 million acres in northern Bahamian waters, 90 miles east of the Florida coast. Water depths range from 650 feet to 7,000 feet. Kerr-McGee completed a speculative seismic acquisition program in 2004. Activity planned for 2005 includes seismic processing and interpretation.

Benin

Block 4 (70%): Kerr-McGee owns a 70% working interest in 2.5 million acres offshore Benin. Water depths on this block range from 300 feet to 10,000 feet. A two-well drilling program was initiated in 2002, and both wells found noncommercial amounts of hydrocarbons. In late 2002, Kerr-McGee and Petronas Carigali Overseas Sdn Bhd. entered into a partnership on the block. The joint venture entered the next three-year phase of exploration in August 2003. Acquisition of additional 2-D seismic data was completed in 2003 to evaluate areas not covered by the existing 3-D seismic data. Kerr-McGee is renegotiating a farmout agreement to reduce its interest in the block to 40%, pending government approval. The company has an obligation to drill one well during the current phase of exploration.

Brazil

BM-ES-9 (50%): This offshore block was acquired in 2001 and extends over 535,000 acres in the Espirito Santo basin in water depths ranging from 4,400 feet to 9,600 feet. During 2002, 3-D seismic data was acquired. An exploratory well at the Tartaruga Verde prospect was drilled in 2004 and was unsuccessful. The company has elected to withdraw from this block and has no further obligations.

BM-C-7 (33 1/3%): In December 2003, Kerr-McGee acquired an interest in 161,000 acres in the Campos basin. Water depth on this block ranges from 300 to 400 feet. In 2004, Kerr-McGee participated in an exploratory well at the Dragon prospect. The well encountered hydrocarbons and oil samples were taken. Kerr-McGee also drilled one vertical appraisal well in late 2004, which was unsuccessful. Additional appraisal drilling and a potential flow test are scheduled for 2005. EnCanBrasil operates the block with 66 2/3% interest.

BM-C-32 (33%), BM-C-30 (25%), BM-C-29 (100%), BM-ES-M-24 (30%), BM-ES-25 (40%): In November 2004, Kerr-McGee acquired an interest in seven blocks, which have since been redesignated as five permit areas located offshore in the prolific Campos and Espírito Santo basins. The blocks are in shallow to deep water (water depths of 200 to 6,600 feet). In the Campos Basin, we operate C-M-101BM-C-30 and C-M-202BM-C29. In the Espirito Santo basin, Devon Energy Corporation operates block C-M-61BM-C-32 and Petrobras operates blocks BM-ES-M-24 and BM-ES-25. To comply with governmental requirements, we expect to increase our interest in C-M-101BM-C-30 to 30%. Work obligations for the contract area include the acquisition of 3-D seismic, as well as an eight-well drilling commitment over a four-year period.

Morocco

Cap Draa block (11.25%): Kerr-McGee and partners had an exploration contract covering approximately 3 million acres along the deepwater shelf edge offshore Morocco, in water depths ranging from 650 feet to 6,500 feet. A 3-D seismic acquisition was completed in 2002. In February 2004, the company executed a farm-out agreement with Shell Oil Company, reducing its interest in this block to 11.25%. In mid-2004, Kerr-McGee participated in the drilling of one exploratory well which was unsuccessful. We have withdrawn from this block and have no further obligations.

Boujdour block (50%): In October 2001, Kerr-McGee acquired a reconnaissance permit covering approximately 27 million acres offshore Morocco from the shoreline to a water depth of more than 10,000 feet. A reconnaissance permit allows Kerr-McGee to perform seismic and related activities for evaluation purposes. In early 2003, we acquired a large 2-D seismic grid. A new seismic and drop core survey was acquired in 2004 and evaluation of the data is currently under way. In 2004, Kerr-McGee, Kosmos Energy Morocco HC and Pioneer Natural Resources Morocco Limited entered into a partnership on the block. Kerr-McGee is involved in discussions with the Moroccan government on future actions.

Gabon

In the Olonga Marin block, Kerr-McGee and partners conducted seismic operations in 2003. The company relinquished its acreage at the end of the exploration period in the first quarter of 2004.

Nova Scotia, Canada

EL2383, EL2386, EL2393 and EL2396 (50%): Kerr-McGee was operator of four deepwater blocks covering approximately 1.5 million acres offshore Nova Scotia, Canada, in water depths ranging from 500 feet to 9,200 feet. The agreements expired in 2004.

EL2398 (66 2/3%), EL2399 (100%) and EL2404 (50%): These Kerr-McGee operated blocks, covering more than 1.5 million acres, are in water depths ranging from 350 feet to 10,000 feet. A regional 2-D seismic program was interpreted in 2001, and additional 2-D seismic data was acquired in 2003. Norsk Hydro has taken a working interest in EL2404 and EL2398 and is providing technical evaluation.

Yemen

Block 50 (47.5%): Kerr-McGee relinquished its interest in block 50 in April 2004.

CHEMICAL OPERATIONS

Kerr-McGee's chemical operations consist of two segments (pigment and other chemical products) that produce and market inorganic industrial chemicals and heavy minerals through its affiliates, Kerr-McGee Chemical LLC, KMCC Western Australia Pty. Ltd., Kerr-McGee Pigments GmbH, Kerr-McGee Pigments International GmbH, Kerr-McGee Pigments Ltd., Kerr-McGee Pigments (Holland) B.V. and Kerr-McGee Pigments (Savannah) Inc. Many of the pigment products are manufactured using proprietary chloride technology developed by the company. Industrial chemicals include titanium dioxide, synthetic rutile, manganese dioxide, boron and sodium chlorate. Heavy minerals produced are ilmenite, natural rutile, leucoxene and zircon. Additionally, Kerr-McGee owns a 50% interest in a joint venture that produces lithium-metal-polymer (LMP) batteries. As discussed under Recent Developments above, Kerr-McGee is pursuing alternatives for the separation of its chemical business.

Exit Activities

In 2004, the company shut down its titanium dioxide pigment sulfate production at its Savannah, Georgia, facility and recognized a pretax charge of $105 million for costs associated with the shutdown. Demand and prices for sulfate anatase pigments, particularly in the paper market, had declined in North America consistently during the past several years. The decreasing volumes, along with unanticipated environmental and infrastructure issues discovered after Kerr-McGee acquired the facility in 2000, created unacceptable financial returns for the facility and contributed to the decision. The company also ended production at its Savannah gypsum plant that used by-product from the sulfate process to manufacture gypsum. The Savannah facility's work force of 410 was reduced by approximately 100 positions. The company expects this decision to result in an improvement in segment operating profit of approximately $15 million annually.

On December 16, 2002, the company announced plans to exit the forest products business due to the strategic focus on the growth of the core businesses, oil and gas exploration and production and the production and marketing of titanium dioxide pigment. Four of the company's five wood-treatment facilities were closed during 2003. The fifth plant, which was a leased facility, ceased all significant operations by the end of 2004 and the assets were sold in early 2005. Results of operations for the forest products business are reflected in the Consolidated Statement of Operations in income (loss) from discontinued operations for all periods presented.

Titanium Dioxide Pigment

The company's primary chemical product is titanium dioxide pigment (TiO_2), a white pigment used in a wide range of products, including paint, coatings, plastics, paper and specialty applications. TiO_2 is used in these products for its unique ability to impart whiteness, brightness and opacity.

Titanium dioxide pigment is produced in two crystalline forms – rutile and anatase. The rutile form has a higher refractive index than anatase titanium dioxide, providing better opacity and tinting strength. Rutile titanium dioxide products also provide a higher level of durability (resistance to weathering). In general, the rutile form of titanium dioxide is preferred for use in paint, coatings, plastics and inks. Anatase titanium dioxide is less abrasive than rutile and is preferred for use in fibers, rubber, ceramics and some paper applications.

Titanium dioxide is produced using one of two different technologies, the chloride process and the sulfate process, both of which are used by Kerr-McGee. Because of market considerations, chloride-process capacity has increased to a substantially higher level than sulfate-process capacity during the past 20 years. The chloride process currently makes up about 60% of total industry capacity and accounts for approximately 83% of the company's gross production capacity.

The company produces TiO_2 pigment at five production facilities. Two are located in the United States, the others are in Australia, Germany and the Netherlands. The following table outlines the company's production capacity by location and process.

TiO_2 Capacity
As of January 1, 2005
(Gross tonnes per year)

Facility	Capacity	Process
Hamilton, Mississippi	225,000	Chloride
Savannah, Georgia	110,000	Chloride
Kwinana, Western Australia (1)	110,000	Chloride
Botlek, Netherlands	72,000	Chloride
Uerdingen, Germany	107,000	Sulfate
Total	624,000	

(1) The Kwinana facility is part of the Tiwest Joint Venture, in which the company owns a 50% undivided interest.

The company owns a 50% undivided interest in a joint venture that operates an integrated TiO_2 project in Western Australia (the Tiwest Joint Venture). The venture consists of a heavy-minerals mine, a minerals separation facility, a synthetic rutile plant and a titanium dioxide plant.

Heavy minerals are mined from 8,513 hectares (21,027 acres) leased by the Tiwest Joint Venture. The company's 50% interest in the properties' remaining in-place proven and probable reserves is 6 million tonnes of heavy minerals contained in 214 million tonnes of sand averaging 2.8% heavy minerals. The valuable heavy minerals are composed of 61% ilmenite, 4.5% natural rutile, 3.4% leucoxene and 10% zircon, with the remaining 21.1% of heavy minerals having no significant value.

Heavy-mineral concentrate from the mine is processed at a 750,000 tonne-per-year dry separation plant. Some of the recovered ilmenite is upgraded at a nearby synthetic rutile facility, which has a capacity of 225,000 tonnes per year. Synthetic rutile is a high-grade titanium dioxide feedstock. The Tiwest Joint Venture provides synthetic rutile feedstock to its 110,000 tonne-per-year titanium dioxide plant located at Kwinana, Western Australia. Production of ilmenite, synthetic rutile, natural rutile and leucoxene in excess of the Tiwest Joint Venture's requirements is sold to third parties, as well as to Kerr-McGee as part of its feedstock requirement for TiO_2 manufacturing under a long-term agreement executed in September 2000.

Information regarding the company's 50% interest in heavy-mineral reserves, production and average prices for the three years ended December 31, 2004, is presented in the following table. Mineral reserves in this table represent the estimated quantities of proven and probable ore that, under presently anticipated conditions, may be profitably recovered and processed for the extraction of their mineral content. Future production of these resources depends on many factors, including market conditions and government regulations.

Heavy-Mineral Reserves, Production and Prices

(Thousands of tonnes)	**2004**	2003	2002
Proven and probable reserves	**5,570**	5,970	5,700
Production	**302**	294	289
Average market price (per tonne)	**$161**	$152	$150

Titanium-bearing ores used for the production of TiO_2 include ilmenite, natural rutile, synthetic rutile, titanium-bearing slag and leucoxene. These products are mined and processed in many parts of the world. In addition to ores purchased from the Tiwest Joint Venture, the company obtains ores for its TiO_2 business from a variety of suppliers in the United States, Australia, Canada, South Africa, Norway, India and Ukraine. Ores are generally purchased under multi-year agreements.

The global market in which the company's titanium dioxide business operates is highly competitive. The company actively markets its TiO_2 utilizing primarily direct sales but also through a network of agents and distributors. In general, products produced in a given market region will be sold there to minimize logistical costs. However, the company actively exports products, as required, from its facilities in the United States, Europe and Australia to other market regions.

Titanium dioxide applications are technically demanding, and the company utilizes a strong technical sales and services organization to carry out its marketing efforts. Technical sales and service laboratories are strategically located in major market areas, including the United States, Europe and the Asia-Pacific region. The company's products compete on the basis of price and product quality, as well as technical and customer service.

Other Chemical Products

The other segment within the chemical operations consisted of the company's electrolytic operations and forest products business. As discussed above, the company sold its remaining assets of the forest products business in January 2005.

Electrolytic Products: Plants at the company's Hamilton, Mississippi, complex include a 135,000 tonne-per-year sodium chlorate facility. Sodium chlorate is used in the environmentally preferred chlorine dioxide process for bleaching pulp. The conversion by the pulp and paper industry to chlorine dioxide technology from chlorine is essentially complete. Over 95% of sodium chlorate is consumed by the pulp and paper industry. Sodium chlorate demand in the United States is expected to increase approximately 2% to 3% per year in the near term as the pulp and paper industry recovers.

The company operates facilities at Henderson, Nevada, producing electrolytic manganese dioxide (EMD) and boron trichloride. Annual production capacity is 29,500 tonnes for EMD and 340,000 kilograms for boron trichloride. Boron trichloride is used in the production of pharmaceuticals and in the manufacture of semiconductors. EMD is a major component of alkaline batteries. The company's share of the North American EMD market is approximately one-third. Demand is being driven by the need for alkaline batteries for portable electronic devices.

In July 2003, the company filed an anti-dumping action against low-priced EMD illegally imported into the U.S. and temporarily idled the Henderson, Nevada, EMD manufacturing facility due to the impact of these imports on market conditions. Partly as a result of the anti-dumping petition, demand for U.S. EMD products increased and the plant resumed operations in December 2003. While the company withdrew the anti-dumping petition in February 2004, we are continuing to monitor market conditions.

As part of the company's strategic decision to focus on the titanium dioxide pigment business, the company continues to investigate divestiture options for the electrolytic business.

Forest Products: The principal product of the forest products business was treated railroad crossties. Other products included railroad crossing materials, bridge timbers and utility poles. As previously discussed, the company ceased significant operations at its remaining wood-treatment plant in December 2004.

Stored Power

The company owns a 50% interest in Avestor, a joint venture formed in 2001 to produce and commercialize a solid-state LMP battery. Compared with traditional lead-acid batteries, Avestor's no-maintenance battery offers superior performance at one-third the size, one-fifth the weight and two to four times the life. The batteries also provide an environmentally preferred alternative since they contain no acid or liquid that may spill or leak. The Avestor joint venture began battery sales in late 2003 from its plant near Montreal, Canada, and started increasing production and sales rates in 2004. Initial battery sales and customer feedback indicate strong demand in the North American telecommunications industry, the initial target market. The European telecommunications market will be the most likely target in 2006. Battery quality and performance are being carefully monitored and evaluated as production rates increase. Development of AVESTOR batteries for industrial and electric utility markets is currently under way, with field trials planned in 2006. With market demand growing, Avestor expects to achieve a breakeven operating cash position in 2006 and anticipates sales matching plant capacity in 2009.

OTHER

Research and Development

The company's Technical Center in Oklahoma City performs research and development in support of existing businesses and for the development of new and improved products and processes. The primary focus of the company's research and development efforts is on the titanium dioxide business. A separate dedicated group at the Technical Center performs research and development in support of the company's battery materials business.

Employees

On December 31, 2004, the company and its affiliates had 4,084 employees. Approximately 888, or 22%, of these employees were represented by chemical industry collective bargaining agreements in the United States and Europe.

Competitive Conditions

The oil and gas exploration and production industry is highly competitive, and competition exists from the initial process of bidding for leases to the sale of crude oil and natural gas. Competitive factors include the ability to find, develop and produce crude oil and natural gas efficiently, as well as the development of successful marketing strategies. Many of the company's competitors, including integrated multinational oil and gas companies, have access to substantially greater financial resources, facilities and staffs than Kerr-McGee.

The titanium dioxide pigment business is highly competitive and some of our competitors have greater financial resources, staffs and facilities. The number of competitors in the industry has declined due to recent consolidations, and this trend is expected to continue. Our competitors' resources may give them various advantages when responding to market conditions. Significant consolidation among the consumers of titanium dioxide has also taken place during the past five years and is expected to continue. Worldwide, Kerr-McGee is one of only five producers that own proprietary chloride-process technology to produce titanium dioxide pigment. Cost efficiency and product quality as well as technical and customer service are key competitive factors in the titanium dioxide business.

It is not possible to predict the effect of future competition on Kerr-McGee's operating and financial results.

GOVERNMENT REGULATIONS AND ENVIRONMENTAL MATTERS

General

The company's affiliates are subject to extensive regulation by federal, state, local and foreign governments. The production and sale of crude oil and natural gas are subject to special taxation by federal, state, local and foreign authorities and regulation with respect to allowable rates of production, exploration and production operations, calculations and disbursements of royalty payments, and environmental matters. Additionally, governmental authorities regulate the generation and treatment of waste and air emissions at the operations and facilities of the company's affiliates. At certain operations, the company's affiliates also comply with certain worldwide, voluntary standards such as ISO 9002 for quality management and ISO 14001 for environmental management, which are standards developed by the International Organization for Standardization, a nongovernmental organization that promotes the development of standards and serves as an external oversight for quality and environmental issues.

Environmental Matters

Federal, state and local laws and regulations relating to environmental protection affect almost all company operations. Under these laws, the company's affiliates are or may be required to obtain or maintain permits and/or licenses in connection with their operations. In addition, these laws require the company's affiliates to remove or mitigate the effects on the environment of the disposal or release of certain chemical, petroleum, low-level radioactive and other substances at various sites. Operation of pollution-control equipment usually entails additional expense. Some expenditures to reduce the occurrence of releases into the environment may result in increased efficiency; however, most of these expenditures produce no significant increase in production capacity, efficiency or revenue.

During 2004, direct capital and operating expenditures related to environmental protection and cleanup of operating sites totaled $32 million. Additional expenditures totaling $99 million were charged against reserves for environmental remediation and restoration. While it is difficult to estimate the total direct and indirect costs to the company of government environmental regulations, the company presently estimates that in 2005 it will incur $11 million in direct capital expenditures, $11 million in operating expenditures and $96 million in expenditures charged to reserves. Additionally, the company estimates that in 2006 it will incur $6 million in direct capital expenditures, $11 million in operating expenditures and $64 million in expenditures charged to reserves.

The company and its affiliates are parties to a number of legal and administrative proceedings involving environmental matters and/or other matters pending in various courts or agencies. These include proceedings associated with businesses and facilities currently or previously owned, operated or used by the company's affiliates and/or their predecessors, and include claims for personal injuries, property damages, breach of contract, injury to the environment, including natural resource damages, and non-compliance with permits. The current and former operations of the company's affiliates also involve management of regulated materials and are subject to various environmental laws and regulations. These laws and regulations obligate the company's affiliates to clean up various sites at which petroleum and other hydrocarbons, chemicals, low-level radioactive substances and/or other materials have been contained, disposed of or released. Some of these sites have been designated Superfund sites by the U.S. Environmental Protection Agency (EPA) pursuant to the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA) and are listed on the National Priority List (NPL).

The company provides for costs related to environmental contingencies when a loss is probable and the amount is reasonably estimable. It is not possible for the company to reliably estimate the amount and timing of all future expenditures related to environmental matters because, among other reasons:

- some sites are in the early stages of investigation, and other sites may be identified in the future;
- remediation activities vary significantly in duration, scope and cost from site to site depending on the mix of unique site characteristics, applicable technologies and regulatory agencies involved;
- cleanup requirements are difficult to predict at sites where remedial investigations have not been completed or final decisions have not been made regarding cleanup requirements, technologies or other factors that bear on cleanup costs;
- environmental laws frequently impose joint and several liability on all potentially responsible parties, and it can be difficult to determine the number and financial condition of other potentially responsible parties and their respective shares of responsibility for cleanup costs;
- environmental laws and regulations, as well as enforcement policies, are continually changing, and the outcome of court proceedings and discussions with regulatory agencies are inherently uncertain;
- unanticipated construction problems and weather conditions can hinder the completion of environmental remediation;
- the inability to implement a planned engineering design or use planned technologies and excavation methods may require revisions to the design of remediation measures, which delay remediation and increase its costs; and
- the identification of additional areas or volumes of contamination and changes in costs of labor, equipment and technology generate corresponding changes in environmental remediation costs.

The company believes that currently it has reserved adequately for the reasonably estimable costs of contingencies. However, additions to the reserves may be required as additional information is obtained that enables the company to better estimate its liabilities, including any liabilities at sites now under review. The company cannot reliably estimate the amount of future additions to the reserves at this time. Additionally, there may be other sites where the company has potential liability for environmental-related matters but for which the company does not have sufficient information to determine that the liability is probable and/or reasonably estimable. We have not established reserves for such sites.

For additional discussion of environmental matters, see Legal Proceedings included in Item 3, *Environmental Matters* section of Management's Discussion and Analysis of Financial Condition and Results of Operations included in Item 7, and Note 19 to the Consolidated Financial Statements in Item 8 of this annual report on Form 10-K.

RISK FACTORS

In addition to the risks identified in Management's Discussion and Analysis included in Item 7 of this annual report on Form 10-K, investors should consider carefully the following risks.

Volatile product prices and markets could adversely affect results of operations and cash flows of the company.

The company's results of operations and cash flows are highly dependent upon the prices of and demand for oil and gas. Historically, the markets for oil and gas have been volatile and are likely to continue to be volatile in the future, and the prices received by the company for its oil and gas production are dependent upon numerous factors that are beyond its control. These factors include, but are not limited to:

- worldwide supply and consumer product demand;
- governmental regulations and taxes;
- the price and availability of alternative fuels;
- the level of imports and exports of oil and gas;
- actions of the Organization of Petroleum Exporting Countries;
- the political and economic uncertainty of foreign governments;
- international conflicts and civil disturbances; and
- the overall economic environment.

The company uses commodity derivative instruments as a means of balancing price uncertainty and volatility with the company's financial and investment requirements. Nevertheless, a sustained period of sharply lower commodity prices could have material adverse effects on the company, including:

- curtailment or deferral of exploration and development projects;
- reduction in the level of economically viable proved reserves;
- reduction of the discounted future net cash flows relating to the company's proved oil and gas reserves;
- reduced ability of the company to maintain or grow its future production through future investment in exploration, exploitation and acquisition activities; and
- reduced ability of the company to borrow funds.

The commodity derivative instruments also may prevent the company from realizing the benefit of price increases above the levels reflected in such contracts. In addition, the commodity derivative instruments may expose the company to the risk of financial loss in certain circumstances, including, but not limited to, instances in which:

- production is less than the volumes covered by the derivative instruments;
- basis differentials tighten substantially from the prices established by these arrangements; or
- the counter-parties to commodity price and basis differential risk management contracts fail to perform as required by the contracts.

The company's debt may limit its financial flexibility.

The company uses both short and long-term debt to finance its operations. The level of the company's debt could affect the company in important ways, including:

- a portion of the company's cash flow from operations will be applied to the payment of principal and interest and will not be available for other purposes;

- ratings of the company's debt and other obligations vary from time to time and impact the costs, terms, conditions and availability of financing;

- covenants associated with debt arrangements require the company to meet financial and other tests that can affect its flexibility in planning for and reacting to changes in its business, including possible acquisition opportunities;

- the company's ability to obtain additional financing for working capital, capital expenditures, acquisitions, general corporate and other purposes may be limited; and

- the company may be at a competitive disadvantage to similar companies that have less debt.

Failure to fund continued capital expenditures and to replace oil and gas reserves could adversely affect results of operations of the company.

The future success of the company's oil and gas business depends upon its ability to find, develop or acquire additional oil and gas reserves that are economically recoverable. The company will be required to expend capital to replace its reserves and to maintain or increase production levels. The company believes that, after considering the amount of its debt, it will have sufficient cash flow from operations, available drawings under its credit facilities and other debt financings to fund capital expenditures. However, if these sources are not sufficient to enable the company to fund necessary capital expenditures, its ability to find and develop oil and gas reserves may be adversely affected and its interests in some of its oil and gas properties may be reduced or forfeited. Further, if oil and gas prices increase, finding costs for additional reserves could also increase, making it more difficult to replace reserves on an economic basis.

Oil and gas exploration, development and production operations involve substantial capital costs and are subject to various economic risks.

The company's oil and gas operations are subject to the economic risks typically associated with exploration, development and production activities. In conducting exploration activities, unanticipated pressure or irregularities in formations, miscalculations or accidents may cause exploration activities to be unsuccessful, and even where oil and gas are discovered it may not be possible to produce or market the hydrocarbons on an economically viable basis. Drilling operations may be curtailed, delayed or canceled as a result of numerous factors, many of which may be beyond the company's control, including unexpected drilling conditions, weather conditions, compliance with environmental and other governmental requirements and shortages or delays in the delivery of equipment and services. The occurrence of any of these or similar events could result in a partial or total loss of investment in a particular property.

The company operates in foreign countries and is subject to political, economic and other uncertainties.

The company conducts significant operations in foreign countries and may expand its foreign operations in the future. Operations in foreign countries are subject to political, economic and other uncertainties, including, but not limited to:

- the risk of war, acts of terrorism, revolution, border disputes, expropriation, renegotiation or modification of existing contracts, import, export and transportation regulations and tariffs;

- taxation policies, including royalty and tax increases and retroactive tax claims;

- exchange controls, currency fluctuations and other uncertainties arising out of foreign government sovereignty over the company's international operations;

- exposure to movements in foreign currency exchange rates, because the U.S. dollar is the functional currency for the company's international operations, except for the company's European chemical operations, for which the euro is the functional currency;

- laws and policies of the United States affecting foreign trade, taxation and investment; and

- the possibility of being subject to the exclusive jurisdiction of foreign courts in connection with legal disputes and the possible inability to subject foreign persons to the jurisdiction of courts in the United States.

Foreign countries have occasionally asserted rights to land, including oil and gas properties, through border disputes. If a country claims superior rights to oil and gas leases or concessions granted to the company by another country, the company's interests could be lost or could decrease in value. Various regions of the world have a history of political and economic instability. This instability could result in new governments or the adoption of new policies that might assume a substantially more hostile attitude toward foreign investment. In an extreme case, such a change could result in termination of contract rights and expropriation of foreign-owned assets. The company seeks to manage these risks by, among other things, focusing much of its international exploration efforts in areas where it believes the existing government is stable and favorably disposed towards United States exploration and production companies.

Competition is intense, and companies with greater financial, technological and other resources may be better able to compete.

The oil and gas exploration and production business and the titanium dioxide pigment business are each highly competitive. In addition to competing with other independent oil and gas producers (i.e., companies not engaged in petroleum refining and marketing operations), the company competes with large, integrated, multinational oil and gas and chemical companies. These companies may have greater resources, which may give them various advantages when responding to market conditions.

The company's business involves many operating risks that may result in substantial losses. Insurance may not be adequate to protect the company against these risks.

The company's operations are subject to hazards and risks inherent in drilling for, producing and transporting oil and gas, as well as in producing chemicals, including, but not limited to: fires; natural disasters; explosions; formations with abnormal pressures; marine risks such as currents, capsizing, collisions and hurricanes; adverse weather conditions; casing collapses, separations or other failures, including cement failure; uncontrollable flows of underground gas, oil and formation water; surface cratering; failure of chemical plant equipment; and environmental hazards such as gas leaks, chemical leaks, oil spills and discharges of toxic gases.

Any of these risks can cause substantial losses in connection with the: injury or loss of life; damage to and destruction of property, natural resources and equipment; pollution and other environmental damage; regulatory investigations and penalties; suspension of operations; and repair and remediation costs.

To help protect against these and other risks, the company maintains insurance coverage against some, but not all, potential losses. Losses could occur for uninsurable or uninsured risks, or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could harm the company's financial condition and results of operations.

Oil and gas reserve information is estimated.

The company's estimates of proved oil and gas reserves are based on internal reserve data prepared by the company's engineers. Petroleum reserve estimation is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in a direct or exact manner. Estimates of economically recoverable oil and gas reserves and of future net cash flows necessarily depend on a number of variable factors and assumptions, including:

- historical production trends from a particular area are representative of future performance;
- data gathered for purposes of reserve estimation, such as well logs and cores, are representative of average reservoir properties;
- assumed effects of regulation by governmental agencies;
- assumptions concerning future oil and gas prices, future development, operating and abandonment costs and capital expenditures; and
- estimates of future severance and excise taxes and workover and remedial costs.

Estimates of reserves prepared or audited by different engineers using the same data, or by the same engineers at different times, may vary substantially. Actual production, revenues and expenditures with respect to the company's reserves will likely vary from estimates, and the variance may be material. The company mitigates the risks inherent to reserve estimation through a comprehensive reserve administration process, which includes review by independent reserve engineers, Netherland, Sewell & Associates, Inc. (NSAI), of the company's procedures and methods for estimating reserves, internal peer review and third-party assessment of significant reserve additions and annual internal review of about 80% of the company's total proved reserves. At December 31, 2004, approximately 43% of the company's proved reserves had been subjected to third-party procedures and methods reviews.

The company is subject to complex laws and regulations, including environmental and safety regulations, that can adversely affect the cost, manner or feasibility of doing business.

The company's operations and facilities are subject to certain federal, state, tribal and local laws and regulations relating to the exploration for, and the development, production and transportation of, oil and gas, and the production of chemicals, as well as environmental and safety matters. Future laws or regulations, any adverse change in the interpretation of existing laws and regulations, inability to obtain necessary regulatory approvals, or a failure to comply with existing legal requirements may harm the company's business, results of operations and financial condition. The company may be required to make large and unanticipated capital expenditures to comply with environmental and other governmental regulations, such as: land use restrictions; drilling bonds, performance bonds and other financial responsibility requirements; spacing of wells; unitization and pooling of properties; habitat and endangered species protection, reclamation and remediation, and other environmental protection; protection and preservation of historic, archaeological and cultural resources; safety precautions; regulations governing the operation of chemical manufacturing facilities; regulation of discharges, emissions, disposal and waste-related permits; operational reporting; and taxation.

Under these laws and regulations, the company could be liable for: personal injuries; property and natural resource damages; oil spills and releases or discharges of hazardous materials; well reclamation costs; remediation and clean-up costs and other governmental sanctions, such as fines and penalties; and other environmental damages.

The company's operations could be significantly delayed or curtailed and its costs of operations could significantly increase beyond those anticipated as a result of regulatory requirements or restrictions. We are not able to predict the ultimate cost of compliance with these requirements or their effect on our operations.

Costs of environmental liabilities and regulation could exceed estimates.

The company and its affiliates are parties to a number of legal and administrative proceedings involving environmental and/or other matters pending in various courts or agencies. These include proceedings associated with facilities currently or previously owned, operated or used by the company's affiliates and/or their predecessors, and include claims for personal injuries, property damages, injury to the environment, including natural resource damages, and non-compliance with permits. The current and former operations of the company's affiliates also involve management of regulated materials that are subject to various environmental laws and regulations. These laws and regulations obligate the company's affiliates to clean up various sites at which petroleum and other hydrocarbons, chemicals, low-level radioactive substances and/or other materials have been disposed of or released. Some of these sites have been designated Superfund sites by the Environmental Protection Agency pursuant to the Comprehensive Environmental Response, Compensation and Liability Act.

The company provides for costs related to environmental matters when a loss is probable and the amount is reasonably estimable. It is not possible for the company to estimate reliably the amount and timing of all future expenditures related to environmental matters for the reasons described above in Items 1 and 2 under Government Regulations and Environmental Matters.

Although management believes that it has established appropriate reserves for cleanup costs, costs may be higher than anticipated and the company could be required to record additional reserves in the future.

The company's oil and gas marketing activities may expose it to claims from royalty owners.

In addition to marketing its oil and gas production, the company's marketing activities generally include marketing oil and gas production for royalty owners. Over the past several years, royalty owners have commenced litigation against a number of companies in the oil and gas production business claiming that amounts paid for production attributable to the royalty owners' interest violated the terms of the applicable leases and laws in various respects, including the value of production sold, permissibility of deductions taken and accuracy of quantities measured. The company could be required to make payments as a result of such litigation, and the company's costs relating to the marketing of oil and gas may increase as new cases are decided and the law in this area continues to develop.

The company is subject to lawsuits and claims.

A number of lawsuits and claims are pending against the company and its affiliates, some of which seek large amounts of damages. Although management believes that none of the lawsuits or claims will have a material adverse effect on the company's financial condition or liquidity, litigation is inherently uncertain, and the lawsuits and claims could have a material adverse effect on the company's results of operations for the accounting period or periods in which one or more of them might be resolved adversely.

AVAILABILITY OF REPORTS AND GOVERNANCE DOCUMENTS

Kerr-McGee makes available at no cost on its Internet website, www.kerr-mcgee.com, its Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to those reports as soon as reasonably practicable after the company electronically files or furnishes such reports to the SEC. Interested parties should refer to the Investor Relations link on the company's website. In addition, the company's Code of Business Conduct and Ethics, Code of Ethics for The Chief Executive Officer and Principal Financial Officers, Corporate Governance Guidelines and the charters for the Board of Directors' Audit Committee, Executive Compensation Committee, and Corporate Governance and Nominating Committee, all of which were adopted by the company's Board of Directors, can be found on the company's website under the Corporate Governance link. The company will provide these governance documents in print to any stockholder who requests them. Any amendment to, or waiver of, any provision of the Code of Ethics for the Chief Executive Officer and Principal Financial Officers and any waiver of the Code of Business Conduct and Ethics for directors or executive officers will be disclosed on the company's website under the Corporate Governance link.

On June 1, 2004, Luke R. Corbett, Chairman and Chief Executive Officer of the company, certified to the New York Stock Exchange that he was not aware of any violation by the company of the New York Stock

Exchange's corporate governance listing standards. In addition, the company filed as exhibits to the company's Form 10-K for the year ended December 31, 2003, the certifications required under section 302 of the Sarbanes-Oxley Act of 2002.

Item 3. Legal Proceedings

A. In 2001, the company's chemical affiliate (Chemical) received a Notice of Violation (NOV) from EPA, Region 9. The NOV claims that Chemical has been in continuous violation of the Clean Air Act new source review requirements applicable to the construction in 1994 and continued operation of an open-hearth furnace at its Henderson, Nevada, facility. Chemical operated the open-hearth furnace in compliance with state-issued permits and believes that the NOV is without substantial merit. During the fourth quarter of 2004, the parties reached an agreement in principle on a settlement that is expected to resolve the NOV. Under the settlement, the government would waive its claim, and Chemical would pay penalties totaling approximately $50,000.

B. In 2002, Tiwest Pty Ltd, an Australian joint venture that produces titanium dioxide and in which Chemical indirectly has a 50% interest, received a complaint and notice of violation from the Department of Environmental Waters and Catchment Protection in Western Australia (the Department) alleging violations of the Environmental Protection Act (1986). This matter concerned an alleged chlorine release at the facility. Tiwest defended the proceeding in the Court of Petty Sessions, Perth, Western Australia, and on March 26, 2004, the Court found in favor of Tiwest. The Department has appealed the Court's decision. Tiwest is vigorously defending against the appeal, and the company believes that, should the Court's ruling be overturned, any fines or penalties related to the matter will not have a material adverse effect on the company.

C. On January 7, 2004, the United States filed a civil lawsuit in the U.S. District Court for the District of Oregon against Kerr-McGee Chemical Worldwide LLC and two other private parties in connection with the remediation of contaminated materials at the White King/Lucky Lass uranium mines in Lakeview, Oregon. The mines were owned and operated by a predecessor of Kerr-McGee Chemical Worldwide LLC and are currently designated as a Superfund site. The lawsuit seeks reimbursement of Forest Service response costs, an injunction requiring compliance with an Administrative Order issued to the private parties regarding cleanup of the site, and civil penalties for alleged noncompliance with the Administrative Order. All legal proceedings have been stayed pending discussions to resolve outstanding issues. The company believes that the litigation will not have a material adverse effect on the company.

D. On September 8, 2003, the Environmental Protection Division of the Georgia Department of Natural Resources (EPD) issued a unilateral Administrative Order to Kerr-McGee Pigments (Savannah) Inc., claiming that the Savannah plant exceeded emission allowances provided for in the facility's Title V air permit. The EPD is seeking monetary penalties of approximately $173,000. The company is vigorously defending against the claims made in the order and, in that connection, the order was appealed, and its effectiveness stayed, on October 8, 2003. The company believes that any penalties related to the Order will not have a material adverse effect on the company.

E. On September 15, 2004, the Missouri Attorney General issued to Kerr-McGee Chemical LLC (Chemical) a Notice of Violations (NOV) of the Missouri Clean Water Act. The NOV alleges the discharge of untreated contaminants from Chemical's plant in Springfield, Missouri to the City of Springfield sanitation system and the Little Sac River. The Attorney General is requesting a civil penalty of $375,000, the performance of an environmental assessment and natural resource damages, which the Missouri Department of Natural Resources currently estimates to be $500,000. The contractor performing the decommissioning work at the plant at the time of the alleged discharge has acknowledged its contractual obligation to indemnify Chemical for costs, damages or fines resulting from its actions. The company believes that the claims made in the NOV are without substantial merit and that any penalties and damages related to the NOV will not have a material adverse effect on the company.

F. For a discussion of other legal proceedings and contingencies, reference is made to the Environmental Matters section of Management's Discussion and Analysis of Financial Condition and Results of Operations included in Item 7 and Note 19 to the Consolidated Financial Statements included in Item 8 of this annual report on Form 10-K, both of which are incorporated herein by reference.

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

None submitted during the fourth quarter of 2004.

Executive Officers of the Registrant

The following is a list of executive officers, their ages, and their positions and offices as of March 1, 2005:

Name	Age	Office
Luke R. Corbett	58	Chief Executive Officer since 1997. Chairman of the Board since May 1999 and from 1997 to February 1999. President and Chief Operating Officer from 1995 until 1997.
Kenneth W. Crouch	61	Executive Vice President since March 2003. Senior Vice President from 1996 to 2003. Senior Vice President, Exploration and Production Operations, from 1998 to 2003. Senior Vice President, Exploration, from 1996 to 1998.
David A. Hager	48	Senior Vice President (oil and gas exploration and production), since March 2003. Vice President of Exploration and Production, 2002 to 2003. Vice President of Gulf of Mexico and Worldwide Deepwater Exploration and Production, 2001 to 2002; Vice President of Worldwide Deepwater Exploration and Production, 2000 to 2001; Vice President of International Operations, 2000; previously Vice President of Gulf of Mexico operations. Joined Sun Oil Co., predecessor of Oryx Energy Company, in 1981. Oryx and Kerr-McGee merged in 1999.
Gregory F. Pilcher	44	Senior Vice President, General Counsel and Corporate Secretary since July 2000. Vice President, General Counsel and Corporate Secretary from 1999 to 2000. Deputy General Counsel for Business Transactions from 1998 to 1999. Associate/Assistant General Counsel for Litigation and Civil Proceedings from 1996 to 1998.
Robert M. Wohleber	54	Senior Vice President and Chief Financial Officer since December 1999. Prior to joining the company in 1999, served as Executive Vice President and Chief Financial Officer of Freeport-McMoRan Exploration Company, President and Chief Executive Officer of Freeport-McMoRan Sulfur and Senior Vice President of Freeport-McMoRan Gold and Copper Corporation, each of which is a natural resources company.
Thomas W. Adams	44	Vice President of Chemical since September 2004. Vice President and General Manager of the Pigment Division from May to September 2004. Vice President of Strategic Planning and Business Development from 2003 to 2004. Vice President of Acquisitions from March 2003 to September 2003. Vice President of Information Management and Technology from 2002 to 2003. Joined Sun Oil Co., predecessor of Oryx Energy Company, in 1982. Oryx and Kerr-McGee merged in 1999.
George D. Christiansen	60	Vice President, Safety and Environmental Affairs, since 1998. Vice President, Environmental Assessment and Remediation, from 1996 to 1998.

Fran G. Heartwell	58	Vice President of Human Resources since March 2003; Director of Human Resources, Kerr-McGee Oil & Gas, from September 2002 to January 2003; Vice President of Human Resources and Administration, Oryx Energy Company, from 1995 until the 1999 merger of Oryx and Kerr-McGee.
Christina M. Poos	35	Vice President and Treasurer since November 2004; Vice President and Treasurer for Kerr-McGee Worldwide Corporation from September to November 2004; Assistant Corporate Controller from February 2004 to September 2004; Manager of Financial Reporting from November 2002 to February 2004. Previously Director of Accounting, Foodbrands America Incorporated (a division of IBP, Inc., a food products company) from June 2000 to September 2002.
J. Michael Rauh	55	Vice President since 1987. Controller from 1987 to 1996 and from January 2002 to present. Treasurer from 1996 to 2002.
John F. Reichenberger	52	Vice President, Deputy General Counsel and Assistant Secretary since July 2000. Assistant Secretary and Deputy General Counsel from 1999 to 2000. Deputy General Counsel from 1998 to 1999. Associate General Counsel from 1996 to 1999.

There is no family relationship between any of the executive officers.

CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

The company makes certain forward-looking statements in this annual report on Form 10-K that are subject to risks and uncertainties. These statements regarding the company's or management's intentions, beliefs or expectations, or that otherwise speak to future events, are based on the information currently available to management. These forward-looking statements include those statements preceded by, followed by or that otherwise include the words "believes," "expects," "anticipates," "intends," "estimates," "projects," "target," "budget," "goal," "plans," "objective," "outlook," "should," or similar words. In addition, any statements regarding possible commerciality, development plans, capacity expansions, drilling of new wells, ultimate recoverability of reserves, future production rates, future cash flows and changes in any of the foregoing are forward-looking statements. Future results and developments discussed in these statements may be affected by numerous factors and risks, such as the accuracy of the assumptions that underlie the statements, the success of the oil and gas exploration and production program, drilling risks, the market value of Kerr-McGee's products, uncertainties in interpreting engineering data, demand for consumer products for which Kerr-McGee's businesses supply raw materials, the financial resources of competitors, changes in laws and regulations, the ability to respond to challenges in international markets, including changes in currency exchange rates, political or economic conditions in areas where Kerr-McGee operates, trade and regulatory matters, general economic conditions, and other factors and risks discussed herein and in the company's other SEC filings, and many such factors and risks are beyond Kerr-McGee's ability to control or predict. Forward-looking statements are not guarantees of performance. Actual results and developments may differ materially from those expressed or implied in this annual report on Form 10-K. Readers are cautioned not to place any undue reliance on any forward-looking statements. Forward-looking statements speak only as of the date of this annual report on Form 10-K. Kerr-McGee undertakes no obligation to update publicly any forward-looking statements, whether as a result of new information, future events or otherwise. For such statements, Kerr-McGee claims the protection of the safe harbor for "forward-looking statements" set forth in the Private Securities Litigation Reform Act of 1995.

PART II

Item 5. Market for the Registrant's Common Equity and Related Stockholder Matters

Information relating to the market in which the company's common stock is traded, the high and low sales prices of the common stock by quarters for the past two years, and the approximate number of holders of common stock is furnished in Note 34 to the Consolidated Financial Statements included in Item 8 of this annual report on Form 10-K.

Quarterly dividends declared totaled $1.80 per share for each of the years 2004, 2003 and 2002. Cash dividends have been paid continuously since 1941 and totaled $205 million in 2004, $181 million in 2003 and $181 million in 2002.

Information required under Item 201(d) of Regulation S-K relating to the company's securities authorized for issuance under equity compensation plans is included in Item 12 of this annual report on Form 10-K.

Item 6. Selected Financial Data

Information regarding selected financial data required in this item is presented in the schedule captioned "Ten-Year Financial Summary" included in Item 8 of this annual report on Form 10-K.

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

Management's Discussion and Analysis

Overview

Kerr-McGee Corporation is one of the largest U.S.-based independent oil and gas exploration and production companies and the world's third-largest producer and marketer of titanium dioxide pigment in terms of volumes produced. Kerr-McGee has three reportable business segments, oil and gas exploration and production, production and marketing of titanium dioxide pigment (chemical - pigment), and production and marketing of other chemical products (chemical - other). Discussion of business developments and results of operations for each of our reportable segments is provided below. The company announced on March 8, 2005, that its Board of Directors authorized management to proceed with its proposal to pursue alternatives for the separation of the chemical business, including a spinoff or sale.

In 2004, we merged with Westport Resources Corporation (Westport), an independent exploration and production company with operations onshore in the United States and in the Gulf of Mexico. The merger, which was completed on June 25, 2004, increased our year-end 2003 proved oil and gas reserves by approximately 30% on a pro forma basis, with year-end 2004 reserves reaching 1.2 billion barrels of oil equivalent. In exchange for Westport's common stock and options, Kerr-McGee issued stock valued at $2.4 billion, options valued at $34 million and assumed debt of $1 billion, for a total of $3.5 billion (net of $43 million of cash acquired). The fair value assigned to assets acquired and goodwill totaled $4.7 billion. The Westport merger added properties to our oil and gas business that are complementary to existing operations. We believe this merger improves the risk profile of our assets by adding low-risk exploitation opportunities and increasing the weight of U.S. onshore natural gas reserves in our portfolio. U.S. onshore reserves increased from 34% of total proved reserves at the beginning of the year to 50% at year-end, largely as a result of our merger with Westport. Additionally, the merger contributed to an increase in proved developed reserves from 50% of total proved reserves at December 31, 2003, to 65% by the end of 2004. Because the percentage of our reserves located onshore in the U.S. increased, we expect that this area will represent a higher proportion of our worldwide production volumes and a larger share of our total capital spending in the future. Based on our current budget, we expect that U.S. onshore production will represent approximately 40% of our total production in 2005 on a barrel of oil equivalent basis, an increase from 34% during 2004, and our capital expenditures in this region are anticipated to increase from 17% of total capital expenditures in 2004 to 32% in 2005.

Strategically, Kerr-McGee focuses on growing its exploration and production operations and improving profitability of its titanium dioxide pigment business through technological advancements and optimization of assets. Additionally, we continue to concentrate on reducing the company's total debt burden to remain competitive and to increase financial flexibility. As a result of certain investing and financing activities, including the Westport merger, the ratio of total debt to total capitalization improved from 58% at year-end 2003 to 41% by the end of 2004 (capitalization is determined as total debt plus stockholders' equity). In February 2005, the company called for redemption all of the $600 million aggregate principal amount of its 5.25% convertible subordinated debentures due 2010 at a price of 102.625%. Prior to March 4, 2005, the redemption date, all of the debentures were converted by the holders into approximately 9.8 million shares of common stock. Pro forma for the conversion, the company's year-end 2004 total debt to total capitalization ratio would have been 34%. On March 8, 2005, the Board of Directors authorized the company to proceed with a share repurchase program initially set at $1 billion. Expanded discussion of the company's cash flows, liquidity and capital resources is included in the *Financial Condition* section below.

We continue to manage risks associated with our environmental remediation responsibilities. Because of the nature of Kerr-McGee's current and historical operations, the company has significant environmental remediation responsibilities and provides reserves for these remediation projects. During 2004, the company provided $92 million (net of reimbursements) for environmental remediation and restoration costs, of which $6 million related to discontinued operations, and funded $49 million of expenditures associated with its environmental projects, net of $50 million in reimbursements received from other parties. A discussion of the status and circumstances surrounding these projects is included in the *Environmental Matters* section below.

The following table summarizes segment operating profit (loss), with a reconciliation to consolidated net income (loss) for each of the last three years:

(Millions of dollars)	**2004**	2003	2002
Segment operating profit (loss) [1] –			
Exploration and production	**$1,249**	$1,002	$ (140)
Chemical –			
Pigment	**(80)**	(13)	24
Other	**(1)**	(23)	(13)
Total Chemical	**(81)**	(36)	11
Total segment operating profit (loss)	**1,168**	966	(129)
Unallocated expenses –			
Interest and debt expense	**(245)**	(251)	(275)
Corporate expenses	**(130)**	(152)	(158)
Environmental provisions, net of reimbursements	**(82)**	(47)	(32)
Other income (expense)	**(40)**	(57)	(31)
Benefit (provision) for income taxes	**(256)**	(195)	35
Total unallocated expenses	**(753)**	(702)	(461)
Income (Loss) from continuing operations	**415**	264	(590)
Discontinued operations, net of taxes	**(11)**	(10)	105
Cumulative effect of change in accounting principle, net of taxes	**-**	(35)	-
Net Income (Loss)	**$ 404**	$ 219	$ (485)
Net Income (loss) per Common Share:			
Basic	**$ 3.20**	$ 2.18	$(4.84)
Diluted	**3.11**	2.17	(4.84)

[1] Segment operating profit (loss) represents results of operations before considering general corporate expenses, interest and debt expense, environmental provisions related to businesses in which the company's affiliates are no longer engaged, other income (expense) and income taxes.

Our results of operations for all periods presented included certain items affecting comparability between periods. Because of their nature and amount, these items are identified separately to help explain the changes in segment operating profit and income (loss) from continuing operations before income taxes between periods, as well as to help distinguish the underlying trends for the company's core businesses. These items are listed in the following table and, to the extent material, are discussed in the *Results of Operations – Consolidated* and *Results of Operations by Segment* sections below.

(Millions of dollars)	**2004**	2003	2002
Included in Total Segment Operating Profit:			
Plant shutdown costs and accelerated depreciation	**$(122)**	$ (45)	$ (12)
Environmental provisions	**(4)**	(13)	(21)
Asset impairments	**(36)**	(14)	(646)
Gain (loss) associated with assets held for sale	**(29)**	45	(176)
Nonhedge derivative loss	**(23)**	–	–
Insurance premium adjustment	**(16)**	–	–
Costs associated with the 2003 work force reduction program	**(2)**	(35)	–
Compensation expense for allocated ESOP shares	**–**	(15)	–
Other	**–**	(4)	(4)
Included in Unallocated Expenses:			
Environmental provisions, net of reimbursements	**(82)**	(47)	(32)
Foreign currency losses	**(21)**	(41)	(38)
Litigation costs	**(6)**	(9)	(72)
Gain on sale of Devon stock	**9**	17	–
Costs associated with the 2003 work force reduction program	**–**	(18)	–
Compensation expense for allocated ESOP shares	**–**	(6)	–
Other	**(4)**	(6)	6
Total items affecting comparability	**$(336)**	$(191)	$(995)

An overview of each segment is included below to provide background information for the various discussions that follow in Management's Discussion and Analysis of Financial Condition and Results of Operations. A detailed discussion of each segment's business and properties is included in Items 1 and 2 of this annual report on Form 10-K.

Exploration and Production – The company's oil and gas business is principally focused on exploration, development and production of crude oil and natural gas. Our core areas of operation are in the Gulf of Mexico, onshore in the United States, the United Kingdom sector of the North Sea and China. In addition, we are actively engaged in exploration efforts within the core areas listed above, as well as in Alaska, Brazil, Morocco, Bahamas, Benin and other areas.

Our exploration and production business is focused on creating shareholder value and profitable growth through exploration, core area exploitation and tactical acquisitions. The first component of our strategy is deepwater-focused exploration in both the Gulf of Mexico and key international basins, complemented by lower risk exploration activities onshore in the U.S., Gulf of Mexico shelf, the North Sea and China. Over the past year, Kerr-McGee has refined its international/new ventures exploration strategy to focus primarily on opportunities in areas with proven world-class hydrocarbon basins such as Brazil and Alaska. We believe this refined strategy will yield more predictable results from exploration and better year-over-year growth performance from the drill-bit.

Cost-efficient core area exploitation is a second key component of the company's strategy. Exploitation and development opportunities within our core areas of operation provide the base cash generation capability of our business and ultimately fund exploration growth opportunities. The company supplements its exploration and exploitation programs with tactical acquisitions in its core producing areas. We only pursue acquisition opportunities where we can add incremental value through unique geological knowledge, utilization of existing infrastructure in the areas acquired or our ability to lower costs.

Commodity prices were relatively high throughout 2004. This price strength, coupled with a 15% increase in average daily production volume, enabled us to fund a $1.2 billion capital expenditure program and still generate significant excess free cash flow. Significant financial and operating milestones achieved by the exploration and production business in 2004 included:

- Successful completion of the Westport merger.
- Operating profit increased 25% over 2003, reaching a record $1.2 billion.
- Average daily production volumes were 312,200 barrels of oil equivalent in 2004, an increase of 15% over 2003, largely due to the Westport merger. We anticipate that 2005 average daily production will range between 352,000 and 367,000 barrels of oil equivalent.
- Replaced 280% of 2004 production largely as a result of the Westport merger.
- Achieved first production from the Red Hawk development in the deepwater Gulf of Mexico. The project was completed on time and within budget.
- Achieved first production from the CFD 11-1 and CFD 11-2 development in Bohai Bay, China. First production was achieved nearly five months ahead of schedule and within budget.

Although the company achieved a number of significant exploration successes in 2004, most were not well enough defined to recognize proved reserves, but may offer potential for future proved reserves additions. 2004 discoveries included:

- Ticonderoga (50% working interest) in the deepwater Gulf of Mexico, which will be developed as a subsea tieback to our Constitution development.
- Nikaitchuq (70%) in Alaska where we drilled two successful wells in 2004. An appraisal and testing program designed to delineate the discovery is currently under way.
- BMC-7 (33%) in the Campos Basin of Brazil. Appraisal of this discovery is ongoing.
- CFD-14-5-1 (100%) in the 09/18 block in Bohai Bay, China. Appraisal planning for this discovery is under way, and we expect to spud the first appraisal well in the first quarter of 2005.

Despite these successes and other successful exploratory wells onshore in the U.S. and in the Gulf of Mexico, the exploration program was unable to deliver an acceptable level of proved reserve additions in 2004, with an exploration-based production replacement of only 34%. To improve the consistency of its exploration performance, the company has refocused its core exploration program in areas with proven world-class hydrocarbon basins. Concentrating our exploration in areas where working hydrocarbon systems are known to exist reduces the geologic risk profile for the company, increasing our chances of discovering economically recoverable accumulations of oil and gas. We believe this shift in focus moves us to a more appropriate overall risk profile. The merger with Westport also is anticipated to provide an important source of future low-risk proved reserve additions. The company believes its refined exploration strategy, supplemented by low- to moderate-risk offshore satellite opportunities and an active U.S. onshore program focused on contributing to our proved reserves, will improve the consistency of results from exploration and deliver better year-over-year performance.

The merger with Westport added substantial depth, breadth and balance to the company's oil and gas operations. Specifically, the merger expanded the company's base of low-risk exploitation projects in the Rocky Mountains, U.S. Gulf Coast and the Mid-Continent/Permian Basin areas. In addition, the merger changed the composition of the company's reserve base, increasing U.S. reserves from 69% at year-end 2003 to 77% at year-end 2004. A significant portion of the acquired U.S. reserves are long-lived natural gas reservoirs. The Westport merger accelerated the company's growth profile, contributing to a 15% increase in production over 2003. Since the completion of the merger, we have moved rapidly to capitalize on new exploitation opportunities, with much of our effort focused in two key fields, the Greater Natural Buttes in Utah and Moxa Arch in Wyoming. This exploitation focus is already generating strong results, with production from Westport's Rocky Mountain properties up by over 15% since the merger.

Our refined exploration strategy has been designed to put the company on track to deliver improved exploration performance in 2005 and beyond. The company has a large portfolio of low-risk exploitation projects, and we intend to capitalize on those opportunities in 2005. For 2005, we have planned the largest exploration and development program in the company's history, including some 900 exploration and development wells, $1.7 billion in capital expenditures and $380 million in exploration costs. We are committing the resources necessary to effectively execute this program with a goal of delivering growth in both reserves and production.

Chemical – Our chemical business has focused its strategy on its titanium dioxide pigment operations. As part of this strategic decision, we continue to investigate divestiture options for the electrolytic business and finalized our exit of the forest products business in early 2005. Results of operations for the forest products business are reflected in the Consolidated Statement of Operations in income (loss) from discontinued operations for all periods presented.

Titanium dioxide pigment is produced using one of two different technologies, the chloride process and the sulfate process. The chloride process produces a pigment with superior brightness and durability preferred by many manufactures of paint, coatings and plastics. In early 2005, chloride-process capacity accounted for 83% of our gross pigment production capacity. The remaining capacity is sulfate-process production, which produces pigment used in paper and specialty products. In the global titanium dioxide pigment industry, Kerr-McGee is the third-largest producer and marketer and one of five companies that own chloride technology.

The profitability and cash flows of the company's pigment operations is directly tied to the global demand, consumption and pricing of titanium dioxide pigment, which tends to follow global economic trends (discussed in the *Operating Environment and Outlook* section below). While the general business environment and pigment pricing play a major role in profitability, execution of asset optimization plans, operations excellence, supply chain management principles, technological innovation and market segmentation further affect performance.

To optimize our assets and improve profitability, the company shut down its Savannah, Georgia, titanium dioxide pigment sulfate facility in 2004. This facility contributed approximately 4% of our total worldwide pigment production in the first half of 2004. Demand and prices for sulfate anatase pigments, particularly in the paper market, had consistently declined in North America during the past several years. The decreasing volumes, along with unanticipated environmental and infrastructure issues discovered after Kerr-McGee acquired the facility in 2000, created unacceptable financial returns for the facility and contributed to the decision. In conjunction with this decision, the company also ended production at its Savannah gypsum plant that used by-product from the sulfate process to manufacture gypsum. In connection with the shutdown, the company recognized a pretax charge of $105 million during 2004.

As part of the company's efforts in the area of technological innovation, low-cost capacity expansions were added to take advantage of future market growth. As a result of these efforts, production began through a new high-productivity oxidation line at the Savannah, Georgia, chloride process pigment plant in early 2004. This new technology is expected to result in low-cost, incremental capacity increases through modification of existing chloride oxidation lines and should allow for improved operating efficiencies through simplification of hardware configurations and reduced maintenance requirements.

The company continues to evaluate the performance of this new oxidation line and expects to have a better understanding of how the Savannah site might be reconfigured to exploit its capabilities in 2005. The possible reconfiguration of the Savannah site, if any, could include redeployment of certain assets, idling of certain assets and reduction of the future useful life of certain assets, resulting in the acceleration of depreciation expense and the recognition of other charges.

The Avestor joint venture was created by Kerr-McGee and Hydro-Quebec, one of North America's largest utilities, to commercialize and produce a lithium-metal-polymer battery. Commercial battery production and sales commenced in late 2003 to the North American telecommunications industry. Production and sales rates increased during 2004 and are expected to continue increasing during 2005. Avestor's unique technical and product offering capability is expected to create additional high-market-value opportunities in the electric utility and industrial battery back-up energy markets. With market demand growing, Avestor expects to achieve a breakeven operating cash position in 2006 and anticipates sales matching plant capacity in 2009.

Operating Environment and Outlook

Oil and Gas Exploration and Production

Commodity Markets – The oil and gas industry enjoyed strong commodity prices throughout 2004. Supply and geopolitical uncertainties, combined with strong demand, resulted in historically high prices for the industry. Prices for West Texas Intermediate (WTI) crude oil averaged $41.40 per barrel for the year, with a low price of about $32.50 per barrel occurring in the first quarter and a high price point in excess of $55.00 per barrel in late October. Crude oil prices were driven largely by geopolitical instabilities in various producing regions, including the Middle East, Nigeria and Venezuela, as well as concerns that world oil production may be challenged to meet overall market demand. These concerns, coupled with rapidly growing demand, particularly in Asian markets, contributed to strong pricing and market volatility. The year ended with WTI crude oil prices at about $43.50 per barrel. U.S. natural gas pricing was also strong throughout the year, with New York Mercantile Exchange (NYMEX) futures prices never falling below $5.00 per million British thermal units (MMBtu). The gas market continues to be driven by fundamental uncertainties regarding the industry's ability to maintain supply in line with increasing demand. In spite of high gas storage inventories, pricing peaked during the fourth quarter of 2004 at around $8.00 per MMBtu. Late in the fourth quarter, prices moderated in response to continued high inventory levels and mild winter conditions for much of the country. For the year, NYMEX natural gas prices averaged about $6.15 per MMBtu and ended the year at about $6.40 per MMBtu. The outlook for the commodity markets in 2005 calls for continued volatility. Most experts see prices for both oil and gas moderating, but remaining above historical levels.

To mitigate uncertainties related to oil and gas price fluctuations, the company enters into derivatives to hedge prices expected to be realized upon the sale of future oil and gas production. Details of the company's commodity derivatives are provided in the *Market Risks* section below.

Industry Environment – Competition in the oil and gas industry for attractive exploration, exploitation and development opportunities is intense. To meet this competition, Kerr-McGee employs a balanced portfolio of attractive exploration opportunities, supplemented by lower-risk satellite and onshore exploration prospects and a strong exploitation project inventory. In addition, the company pursues tactical acquisitions, property exchanges and other business development activity to augment its exploration, exploitation and development programs.

The company's exploration portfolio is anchored by a large acreage and prospect inventory. The company makes extensive use of technology and highly trained geoscientists to effectively evaluate prospects, reducing pre-drill risk to an acceptable level. The company maintains a dedicated exploration technology group which focuses on 3-D visualization technology, seismic data processing and interpretation, and application of new and emerging technologies to more effectively evaluate exploration prospects. Over the past year, our exploration efforts have been refocused on proven world-class hydrocarbon basins to lower the overall risk profile. The company maintains a core group of highly experienced development personnel to quickly and efficiently exploit attractive new offshore oil and gas discoveries using new technologies. We currently operate five facilities in the deepwater Gulf of Mexico. This infrastructure provides Kerr-McGee with a competitive advantage, enabling the company to efficiently employ a hub-and-spoke concept of satellite exploration and exploitation of nearby opportunities. One of the company's key strengths is its ability to profitably develop smaller offshore oil and gas discoveries that previously might have been considered uneconomical.

The company's acquisition of HS Resources in 2001 and Westport in mid-2004 greatly enhanced its inventory of low-risk natural gas exploitation opportunities in the Rocky Mountain region. These gas resources are long life reservoirs, which work to stabilize the company's production base. The relatively low risk nature of these opportunities provides balance to the company's exploration program. In the U.K. the company also employs a hub and spoke development philosophy utilizing Kerr-McGee's operated infrastructure as a base for satellite exploration and exploitation of nearby opportunities.

The company utilizes regional business development teams to evaluate tactical acquisition and trade opportunities to supplement its exploration and exploitation efforts. A good example is the recently announced trade of our U.S. onshore Arkoma Basin properties for British Petroleum's interest in the Blind Faith discovery in the Gulf of Mexico. The transaction provided the company with a 37.5% interest in a new offshore discovery, which Kerr-McGee plans to quickly develop into new proved reserves and production.

In 2005, with higher commodity prices, the company expects competition for high-quality exploration and exploitation opportunities to remain strong. The company will continue to refine the exploration, exploitation and business development approach described above to gain competitive advantage among its peers.

Chemical

Titanium dioxide is a quality-of-life product, and its consumption follows general economic trends. Coming off a challenging year in 2003, business conditions for the company's chemical operations improved in 2004 due to general strengthening of the global economy. These economic forces created increases in demand, pushing capacity utilization higher and reduced overall inventory levels, thereby creating an environment favorable for product price gains. Partially offsetting the general economic robustness, were the impacts of higher energy prices on our operations and the weakening of the U.S. dollar, which weakened local pricing dynamics in various global markets. While overall global economic growth was strong throughout 2004, the last quarter of 2004 did begin to show signs of a leveling off in the leading U.S. economic indicators and Euro-zone gross domestic product. Moving into 2005, general economic conditions are expected to resemble more normal growth patterns, particularly in North America and Europe, while Asian markets are expected to lead the way, as they did in 2004.

The strategy for Kerr-McGee's chemical unit focuses on continued improvement in asset productivity, process and product capability, cost reductions and providing superior products for market-segment growth. Multiple initiatives are being pursued to capture new market growth through segmentation strategies that align products with customer needs, low-cost plant modifications to increase production capacity, continuous improvement programs to increase efficiency and lower operating costs, and technology-based programs to improve product quality and lower costs.

Results of Operations - Consolidated

The following discussion presents results of consolidated operations, with additional analysis of segment operations included in *Results of Operations by Segment.*

Revenues - The increase in 2004 revenues was primarily due to higher average realized sales prices and higher sales volumes for crude oil, natural gas and titanium dioxide pigment. Approximately 87% of the 2004 growth in consolidated revenues was generated by our oil and gas exploration and production segment. Oil and gas sales volumes on a barrel of oil equivalent basis increased 15% over 2003 volumes as a result of the Westport merger completed in June 2004. Oil and gas sales volumes declined in 2003 compared to 2002 primarily due to property divestitures. Average prices realized from sales of oil and gas, including the effect of realized losses on our hedging contracts, increased by 13% in 2004 and 29% in 2003 as a result of stronger commodity prices. Gas marketing sales revenues increased by $121 million in 2004 and $228 million in 2003 largely as a result of higher natural gas marketing volumes and prices. These increases were offset by higher gas purchase costs. Improvement in the general economic conditions favorably affected pigment sales volumes in 2004 and 2003, contributing to growth in our consolidated revenues. A summary of components of changes in consolidated revenues over the three-year period ended December 31, 2004, is presented below. Additional analysis of factors contributing to these changes is included in *Results of Operations by Segment.*

(Millions of dollars)	2004	2004 vs. 2003	2003	2003 vs. 2002	2002
Revenues	$5,157	$1,077	$4,080	$ 565	$3,515
Increase (decrease) in:					
Oil and gas sales revenues due to volume changes		$ 405		$(362)	
Oil and gas sales revenues due to changes in realized prices		385		594	
Gas marketing sales revenues		121		228	
Other exploration and production segment revenues		21		13	
Pigment sales revenues due to volume changes		114		(10)	
Pigment sales revenues due to changes in realized prices		16		94	
Other chemical segment revenues		15		8	
Total change in revenues		$1,077		$ 565	

Costs and Operating Expenses - Costs and operating expenses during 2004 increased by $390 million, or 25%, over 2003, largely due to higher lease operating expenses, gas purchase costs and pigment production costs. The increase in lease operating expenses is primarily attributable to the Westport merger. Cost of natural gas marketed and associated transportation expenses increased by $127 million, more than offsetting the increase in gas marketing sales revenues discussed above. Additionally, higher pigment sales volume and average cost contributed to the 2004 increase. Costs and operating expenses for 2003 increased $220 million over 2002, primarily due to higher gas marketing costs of $233 million (which offset higher gas marketing sales revenues), higher pigment production costs of $35 million and 2003 plant shutdown provisions associated with the closure of the synthetic rutile facility in Mobile, Alabama. These increases were partially offset by lower lease operating expense of $114 million, mainly due to oil and gas property divestitures.

(Millions of dollars)	2004	2004 vs. 2003	2003	2003 vs. 2002	2002
Costs and Operating Expenses	$1,953	$390	$1,563	$ 220	$1,343
Increase (decrease) in:					
Lease operating expense		$118		$(114)	
Gas purchase costs		127		233	
Costs associated with plant shutdowns		16		28	
Pigment production costs		108		35	
Other costs and operating expenses		21		38	
Total change in costs and operating expenses		$390		$ 220	

Selling, General and Administrative Expenses - The decrease of $28 million from 2003 to 2004 was mainly due to certain 2003 expenses that did not reoccur, partially offset by higher compensation costs. In 2003, we initiated a work force reduction program and recorded a total charge of $53 million, of which $48 million was included as a component of selling, general and administrative expenses and $5 million was included in other categories of operating expenses. An additional $1 million of costs associated with the 2003 work force reduction program was incurred in 2004. Recurring employee-related costs, primarily incentive compensation, increased by $32 million in 2004. During 2003, selling, general and administrative expenses increased 19% over 2002, primarily due to provisions associated with the 2003 work force reduction program and additional compensation expense resulting from loan prepayments required to release shares from the company's employee stock ownership plan. Additionally, higher expense associated with incentive compensation awards and pension and postretirement benefits contributed to the 2003 increase. These increases were partially offset by a decrease in litigation provisions. In 2002, we recognized a charge of $72 million mainly related to certain forest products litigation in Mississippi, Louisiana and Pennsylvania. This litigation is discussed in Note 19 to the Consolidated Financial Statements included in Item 8 of this annual report on Form 10-K.

(Millions of dollars)	2004	2004 vs. 2003	2003	2003 vs. 2002	2002
Selling, general and administrative expenses	$337	$(28)	$365	$57	$308
Increase (decrease) in:					
Cost of the 2003 work force reduction program		$(47)		$48	
Compensation expense for allocated ESOP shares		(16)		16	
Other compensation, including incentive compensation		32		21	
Litigation provisions		3		(63)	
Other selling, general and administrative expenses		-		35	
Total change in selling, general and administrative expenses		$(28)		$57	

Depreciation and Depletion - The 2004 increase reflects the impact of the Westport merger, changes in reserve estimates for certain oil and gas properties and accelerated depreciation associated with chemical plants. The decrease in 2003 is due to divested or held-for-sale oil and gas properties and lower depletion on the Leadon field, the value of which was written down in 2002, partially offset by higher depletion expense in the Gulf of Mexico region, mainly due to increased oil and gas production volumes.

(Millions of dollars)	2004	2004 vs. 2003	2003	2003 vs. 2002	2002
Depreciation and depletion	$1,060	$318	$742	$ (67)	$809
Increase (decrease) in:					
Oil and gas depletion due to change in depletion rates		$150		$ 19	
Oil and gas depletion due to change in sales volumes		95		(100)	
Chemical segment accelerated depreciation		71		3	
Other depreciation		2		11	
Total change in depreciation and depletion		$318		$ (67)	

Exploration Expense - Total exploration expense of $356 million in 2004 remained substantially unchanged from 2003. Exploration expense in 2003 was higher than in 2002 by $81 million. Components of exploration expense are further analyzed in *Results of Operations by Segment - Exploration and Production.*

Interest and Debt Expense - Interest and debt expense for 2004, 2003 and 2002 was $245 million, $251 million and $275 million, respectively. The 2004 decrease of $6 million was due to an increase in capitalized interest and higher realized gains on interest rate swaps designated to hedge the fair value of our debt. For additional information regarding these instruments, refer to the *Market Risks* section below. The decrease from 2002 to 2003 was attributable to lower average borrowings under revolving credit facilities and commercial paper of approximately $570 million and slightly lower average interest rates on the company's long-term debt.

Shipping and Handling Expenses - Shipping and handling expenses for 2004, 2003 and 2002 were $166 million, $139 million and $124 million, respectively. An analysis of transportation and shipping and handling expenses is provided in *Results of Operations by Segment* below.

Accretion Expense - Accretion expense for 2004 and 2003 was $30 million and $25 million, respectively. The increase during 2004 resulted primarily from an increase in our asset retirement obligations associated with Westport properties.

Asset Impairments - Asset impairment charges totaled $36 million in 2004, $14 million in 2003 and $646 million in 2002. Our chemical - pigment segment incurred an asset impairment of $8 million in 2004 (related to the shutdown of the sulfate-process titanium dioxide pigment production at the Savannah, Georgia, plant). The remaining asset impairment charges were related to our exploration and production segment and are discussed in more detail in *Results of Operations by Segment - Exploration and Production.*

Gains (Losses) Associated with Assets Held for Sale - Net gains (losses) associated with assets held for sale in 2004, 2003 and 2002 were $(29) million, $45 million and $(176) million, respectively, all of which related to our oil and gas exploration and production segment. Additional discussion of these gains and losses is provided in *Results of Operations by Segment - Exploration and Production.*

Taxes, Other than Income Taxes - Taxes, other than income taxes totaled $148 million, $96 million and $102 million in 2004, 2003 and 2002, respectively, and includes $104 million, $52 million and $67 million, respectively, of oil and gas production and ad valorem taxes. Because oil and gas production taxes are generally determined as a percentage of oil and gas sales revenues, they fluctuate with changes in oil and gas sales volumes and realized prices. Oil and gas production and ad valorem taxes increased $52 million in 2004 compared to 2003 due to higher sales volumes primarily as a result of the Westport merger and higher realized prices. The decrease from 2002 to 2003 was caused by elimination of royalty payments in the U.K. North Sea and lower sales volumes due to property divestitures. Taxes, other than income taxes also includes payroll and ad valorem taxes, which did not change significantly over the three-year period ended December 31, 2004.

Provision for Environmental Remediation and Restoration - Provision for environmental remediation and restoration, net of reimbursements, totaled $86 million, $60 million and $53 million in 2004, 2003 and 2002, respectively. Our environmental obligations are discussed in detail under *Environmental Matters* below.

Other Income (Expense) - Other income (expense) totaled $(40) million, $(57) million and $(31) million, which included $(21) million, $(41) million and $(38) million in 2004, 2003 and 2002, respectively, of net foreign currency losses. The majority of the foreign currency losses resulted from the company's U.K. operations due to unfavorable changes in the U.S. dollar/British pound sterling exchange rates. Additionally, equity in net losses of equity method investees, net of gains, totaled $26 million, $33 million and $25 million in 2004, 2003 and 2002, respectively, and were primarily the result of the investment in the Avestor joint venture formed in 2001 to develop lithium-metal-polymer batteries. These losses were partially offset in 2004 and 2003 by gains on sales of Devon common stock. In December 2003, we sold a portion of our investment in Devon shares classified as available for sale, resulting in a pretax gain of $17 million. The remaining shares classified as available for sale were sold in January 2004 for a pretax gain of $9 million. Through August 2, 2004, we also held 8.4 million shares of Devon common stock classified as trading. On August 2, 2004, these shares were distributed to the holders of our debt exchangeable for common stock to repay the debt at maturity. During 2002, 2003 and through August 2, 2004, other income (expense) included net gains of $27 million, $8 million and $2 million representing changes in the fair value of Devon common stock classified as trading and changes in the estimated fair value of options embedded in the debt exchangeable for common stock.

Provision (Benefit) for Income Taxes - The effective tax rate for 2004 was 38.2%, compared with 42.5% in 2003 and (5.6)% in 2002. The effective tax rate declined in 2004 because of decreased proportion of income from continuing operations attributable to foreign operations. The 2002 tax benefit was reduced from the U.S. statutory rate due to deferred tax expense of $132 million associated with a 33% increase in the U.K. corporate tax rate for oil and gas companies, together with the impact of taxation on foreign operations.

Income (Loss) from Discontinued Operations - The company recognized a loss from discontinued operations as a result of its decision to dispose of the forest products business of $11 million, $10 million and $21 million, net of tax benefit, for the years 2004, 2003 and 2002, respectively. Prior to its disposition, the forest product business represented a component of our chemical – other segment. The 2002 income from discontinued operations also includes income of $126 million (including tax benefit of $22 million) resulting from the company's decision in early 2002 to dispose of its exploration and production interests in Indonesia and Kazakhstan and its interest in the Bayu-Undan project in the East Timor Sea offshore Australia. The $126 million income included a net pretax gain on sale of $72 million associated with the divestitures. These divestiture decisions were made as part of the company's strategic plan to rationalize noncore chemical and oil and gas assets.

Cumulative Effect of Change in Accounting Principle - We recognized a loss of $35 million (net of income tax benefit of $18 million) in 2003 upon adoption, as of January 1, 2003, of Financial Accounting Standards Board Statement No. 143 (FAS No. 143), "Accounting for Asset Retirement Obligations." Adoption of this standard also resulted in an increase in net property of $108 million, an increase in abandonment liabilities of $161 million and a decrease in deferred income tax liabilities of $18 million.

Results of Operations by Segment

EXPLORATION AND PRODUCTION

Segment Operating Profit

Revenues, operating costs and expenses relating to the production, sale and marketing of crude oil, condensate and natural gas are shown in the following table.

(Millions of dollars)	**2004**	2003	2002
Revenues, excluding marketing revenues	**$3,436**	$2,625	$2,380
Operating costs and expenses:			
Lifting costs:			
Lease operating expense	**452**	334	448
Production and ad valorem taxes	**104**	52	67
Total lifting costs	**556**	386	515
Depreciation, depletion and amortization	**854**	609	690
Accretion expense (abandonment obligations)	**30**	25	–
Asset impairments	**28**	14	646
Loss (gain) associated with assets held for sale	**29**	(45)	176
General and administrative expense	**135**	127	87
Transportation expense	**111**	94	84
Gas gathering, pipeline and other expenses	**89**	66	61
Exploration expense	**356**	354	273
Total operating cost and expenses	**2,188**	1,630	2,532
Operating profit (loss), excluding net marketing margin	**1,248**	995	(152)
Marketing - Gas sales revenues	**419**	298	70
Marketing - Gas purchase cost (including transportation)	**(418)**	(291)	(58)
Net marketing margin	**1**	7	12
Total Operating Profit (Loss)	**$1,249**	$1,002	$ (140)

Operating profit (loss) for all periods presented included certain items affecting comparability between periods. Because of their nature and amount, these items are identified separately to help explain the changes in operating profit (loss) between periods, as well as to help distinguish the underlying trends for the segment's core business. These items are listed in the following table and, to the extent material, are discussed in the analysis of operating profit components that follows:

(Millions of dollars)	**2004**	2003	2002
Asset impairments	**$(28)**	$(14)	$(646)
Gain (loss) associated with assets held for sale	**(29)**	45	(176)
Nonhedge derivative loss	**(23)**	–	–
Insurance premium adjustment	**(12)**	–	–
Costs associated with the 2003 work force reduction program	**(1)**	(14)	–
Environmental provisions	**–**	–	(11)
Compensation expense for allocated ESOP shares	**–**	(9)	–
Other	**(4)**	(5)	(2)
Total items affecting comparability	**$(97)**	$ 3	$(835)

Revenues

Revenues, production statistics and average prices received from sales of crude oil, condensate and natural gas are shown in the following table (exclusive of discontinued operations):

(Millions of dollars, except per-unit amounts)	**2004**	2003	2002
Revenues –			
Crude oil and condensate sales	**$1,644**	$1,426	$1,531
Natural gas sales	**1,728**	1,156	819
Gas marketing activities	**419**	298	70
Other revenues	**87**	43	30
Nonhedge derivative losses	**(23)**	–	–
Total	**$3,855**	$2,923	$2,450
Production –			
Crude oil and condensate (thousands of barrels per day):			
U.S. Gulf of Mexico	**59.9**	56.8	52.7
U.S. onshore	**28.2**	19.7	28.6
North Sea	**62.3**	71.6	102.8
China	**8.4**	2.1	3.3
Other International	**–**	–	3.9
Total	**158.8**	150.2	191.3
Natural gas (MMcf per day):			
U.S. Gulf of Mexico	**364**	277	273
U.S. onshore	**472**	352	386
North Sea	**85**	97	101
Total	**921**	726	760
Total equivalent barrels of oil (thousands of barrels per day)	**312**	271	318
Average sales prices (excluding hedges) [1] –			
Crude oil and condensate (per barrel):			
U.S. Gulf of Mexico	**$37.97**	$29.14	$22.73
U.S. onshore	**37.63**	27.42	22.12
North Sea	**35.77**	28.26	23.75
China	**32.37**	29.66	24.84
Other International	**–**	–	20.28
Average	**36.76**	28.50	23.17
Natural gas (per Mcf):			
U.S. Gulf of Mexico	**$ 6.25**	$ 5.60	$ 3.39
U.S. onshore	**5.92**	4.87	2.81
North Sea	**4.06**	3.09	2.35
Average	**5.88**	4.92	2.96
Average realized sales prices (including hedges) [1] –			
Crude oil and condensate (per barrel):			
U.S. Gulf of Mexico	**$29.43**	$26.12	$21.58
U.S. onshore	**28.43**	26.23	21.50
North Sea	**26.50**	25.82	22.41
China	**32.37**	29.66	24.84
Other International	**–**	–	20.28
Total	**28.23**	26.04	22.04
Natural gas (per Mcf):			
U.S. Gulf of Mexico	**$ 5.44**	$ 4.88	$ 3.23
U.S. onshore	**5.08**	4.31	2.91
North Sea	**4.06**	3.09	2.35
Total	**5.13**	4.37	2.95

(1) Prices are shown both with and without the impact of the company's oil and gas hedging program which began in 2002.

Crude Oil Sales Revenues and Production - Oil sales revenues increased $218 million or 15% in 2004 compared with 2003 due to a combination of higher production and higher realized commodity prices. Oil production of 159 thousand barrels per day (Mbbls/d) in 2004 represented an increase of almost 6% over 2003 levels, primarily due to the contribution of Westport assets acquired in late June 2004 (14 Mbbls/d). In addition, China's CFD 11-1/11-2 fields started producing in July 2004 and the Gulf of Mexico's Gunnison field, which began production in the fourth quarter of 2003, contributed to the increase. Production volume increases in the U.S. and China were partially offset by a 13% decline in North Sea production. The North Sea production decrease was primarily due to declines at Tullich, Harding and Leadon, partially offset by strong 2004 development drilling results at the Gryphon field. Average oil prices, including the effect of hedging activity, increased $2.19 per barrel in 2004, resulting in a $128 million increase in sales revenues.

Oil production in 2003 was 150 Mbbls/d, down 21% compared to 2002, primarily due to the sale of various noncore properties during 2003 and 2002. The company began a divestiture program in mid-2002 to improve the overall quality of its asset portfolio, targeting high-operating-cost, noncore assets. The program was completed in 2003. Property sales were concentrated in the U.S. onshore area, Gulf of Mexico shelf and the North Sea, as well as Ecuador and the South China Sea. After adjusting for divestitures, 2003 oil production was approximately the same as 2002.

Oil sales revenues decreased $105 million in 2003 compared with 2002, primarily as a result of lower production due to the property divestitures in 2002 and 2003. The effect of the 41 Mbbl/d decrease in oil production on sales revenues was partially offset by the effect of higher realized prices. The average realized price, including the effect of hedging activity increased $4 per barrel, adding $220 million to oil sales revenues, while lower oil production reduced revenues by $325 million.

Natural Gas Sales Revenues and Production - Natural gas sales revenues increased $572 million in 2004 compared to 2003 as a result of a 27% increase in gas production, combined with a $.76 per Mcf increase in the average realized price. Gas production in 2004 was 921 MMcf per day, 195 MMcf per day above 2003 annual production, contributing an additional $315 million in gas sales revenues. Gas production increased as a result of additional production from Westport assets, which contributed approximately 197 MMcf per day in 2004. In addition, new production from deepwater Gulf of Mexico fields, primarily Red Hawk and Gunnison, offset declines that occurred in the U.S. onshore area, as well as the North Sea Tullich field. The Red Hawk field began production in July 2004. Higher realized gas prices provided an additional $257 million in gas sales revenues, averaging $5.13 per Mcf, including the impact of hedging activity.

Natural gas sales revenues in 2003 were $337 million higher than in 2002, primarily as a result of a $1.42 per Mcf increase in the average realized price for natural gas, partially offset by a 5% decline in production. Higher realized prices in 2003 increased revenue by $374 million, while lower gas production reduced revenues by $37 million. Production declines resulted primarily from property divestitures concentrated in the U.S. onshore and Gulf of Mexico shelf areas. After adjusting for divestitures, 2003 gas production volumes declined by 2% compared with 2002.

Other Revenues - Other revenues include gas processing plant and gathering system revenues in the U.S. onshore area, along with oil tariffs and non-equity oil and gas sales in the U.K. Gas marketing activities in the Rocky Mountain area are discussed below.

Other revenues totaled $87 million in 2004, an increase of $44 million over 2003. The increase is primarily the result of higher U.S. commodity prices impacting sales generated from the company's ownership interest in gas plants and gathering systems located in Louisiana and Colorado ($21 million). In addition, the North Sea generated higher revenues from resale of non-equity gas, an increase of $10 million in 2004 compared with 2003.

Other revenues increased by $13 million in 2003 from $30 million reported in 2002. The increase is primarily due to higher U.S. natural gas prices favorably impacting gas processing plant and gas gathering revenues in the U.S. onshore area.

Nonhedge Derivative Losses - Nonhedge derivative losses represent net realized and unrealized gains and losses related to crude oil and natural gas derivative instruments that have not been designated as hedges or that do not qualify for hedge accounting treatment. In the second quarter of 2004, we entered into financial derivative instruments in the form of fixed-price swaps and costless collars relating to specified quantities of projected 2004-2006 production that was not already hedged, including unhedged production from the Westport properties. Certain crude oil and natural gas swaps covering the period from August to December 2004 were characterized initially as nonhedge derivatives since either our U.S. production (excluding Westport volumes) was already hedged or, in the case of Rocky Mountain production, we did not have sufficient basis swaps in place to ensure that the hedges would be highly effective. Consequently, we recognized mark-to-market losses of $10 million in earnings during the second quarter associated with these derivatives. After the Westport merger closed and with sufficient oil and gas production available, these swaps were designated as hedges and, as such, realized gains and losses thereafter were recognized in earnings when the hedged production was sold.

In connection with the Westport merger, we recognized a $196 million net liability associated with Westport's existing commodity derivatives at the merger date (June 25, 2004). Some of these derivative instruments were designated as hedges in July 2004 in connection with the redesignation of acquisition-related derivatives described above, while others do not qualify for hedge accounting treatment. In the second quarter of 2004, we recognized a mark-to-market gain of $15 million in earnings since the value of the net derivative liability had decreased to $181 million by June 30, 2004.

Westport's derivatives in place at the merger date consisted of fixed-price oil and gas swaps, natural gas basis swaps, and costless and three-way collars. The swaps qualify for hedge accounting and were designated as hedges after the merger date. Accordingly, future realized gains and losses on those derivative instruments are reflected in earnings when the hedged production is sold. However, the costless and three-way collars – each of which was in a liability position – do not qualify for hedge accounting treatment under existing accounting standards because they represent "net written options" at the merger date. As a result, even though these collars effectively reduce commodity price risk, we will continue to recognize mark-to-market gains and losses in earnings until the collars mature, rather than defer such amounts in accumulated other comprehensive income (loss). In the second half of 2004, we recognized losses of $28 million associated with Westport's collars. The net derivative liability associated with these derivatives at year-end 2004 was $69 million.

For further discussion of the company's derivative activities, see Note 11 to the Consolidated Financial Statements included in Item 8 of this annual report on Form 10-K. A full description of open derivative positions, both for hedge and nonhedge derivatives, is included in the Market Risks section below.

Lease Operating Expense

During 2004, lease operating expense increased 35% or $118 million compared with 2003. On a per-unit basis, 2004 lease operating expense increased $.58 per barrel of oil equivalent (boe) to $3.95 per boe compared to $3.37 per boe for 2003. The increase was primarily due to additional operating expenses associated with Westport assets ($66 million), start-up production costs at China's CFD 11-1/11-2 fields, and higher expense in the Gulf of Mexico deepwater related to an operating lease for platform infrastructure at the Gunnison field. Also contributing to the increase were higher pension and contract labor costs for nonoperated properties in the North Sea. A charge of $12 million in 2004, or $.11 per boe, for a property insurance premium adjustment primarily associated with higher industry losses due to Hurricane Ivan, also contributed to the year-over-year increase.

Lease operating expense in 2003 was $114 million lower than 2002, a decrease of 25%. On a per-unit basis, lease operating expense decreased by about 13% to $3.37 per boe in 2003 from $3.87 per boe in 2002. Lower operating expenses were primarily related to the divestment of noncore, high-operating-cost properties in 2002 and early 2003.

Production and Ad Valorem Taxes

Production and ad valorem taxes are comprised primarily of severance taxes associated with properties located onshore and in state waters in the U.S. These taxes, which usually are based on a percentage of oil and gas sales revenues, increased $52 million in 2004 as a result of higher commodity prices and higher sales volumes. The addition of Westport's properties resulted in higher production taxes as a percentage of sales revenues by increasing the proportion of U.S. onshore properties subject to production taxes in our portfolio.

Production taxes of $52 million in 2003 were $15 million lower than 2002 primarily due to the elimination of royalty payments in the U.K. North Sea and lower production volumes. These factors were partially offset by the impact of higher commodity prices on production taxes.

Depreciation, Depletion and Amortization (DD&A)

DD&A expense of $854 million for 2004 increased $245 million over the prior year, primarily caused by additional DD&A expense for the recently acquired Westport properties ($206 million). On a per-unit basis, DD&A increased from $6.16 per boe in 2003 to $7.47 per boe in 2004, reflecting the impact of the Westport merger which had a higher acquisition cost per boe than our historical asset base. In addition, DD&A unit costs increased in the North Sea area due to a reduction in the expected life and field facility salvage values on certain fields, combined with the impact of changes in reserve estimates. We expect 2005 per-unit DD&A costs to average between $8.60 per boe and $8.75 per boe.

DD&A expense in 2003 was $609 million, representing a 12% decline compared with 2002. The decrease was primarily the result of reduced production due to the divestiture program that began in mid-2002 and asset impairments that were recorded in 2002 (primarily the Leadon field). On a per-unit basis, DD&A expense increased 3% to $6.16 per boe in 2003 from $5.97 per boe in 2002. Although total DD&A expense was lower, per unit costs increased, reflecting the company's divestiture activity and a change in the overall mix of producing properties between 2003 and 2002. In accordance with accounting standards, depletion expense was not recorded for various assets that were designated as held-for-sale in 2002, although production quantities for these properties continued to be included in the calculation of overall per-unit DD&A.

Accretion Expense

Accretion expense increased by $5 million in 2004 compared to 2003, reflecting an increase in our asset retirement obligations associated with the Westport properties. Accretion expense of $25 million in 2003 resulted from the initial implementation of FAS No. 143. Prior to 2003, abandonment costs were recorded as DD&A expense on a per-unit basis (undiscounted) as oil and gas was produced.

Asset Impairments and Gain (Loss) associated with Assets Held for Sale

Kerr-McGee records impairment losses when performance analysis and other factors indicate that future net cash flows from production will not be sufficient to recover the carrying amounts of the related assets. In general, such write-downs often occur on mature properties that are nearing the end of their productive lives or cease production sooner than anticipated. Asset impairment losses recorded in 2004 and 2003 totaled $28 million and $14 million, respectively. Asset impairment losses in 2004 related in large part ($17 million) to two U.S. Gulf of Mexico fields that experienced premature water breakthrough and ceased production sooner than expected. In addition, an $8 million impairment loss was recognized for a North Sea field that is no longer certain to be developed and a $3 million impairment loss was recognized for other minor U.S. onshore properties.

The 2003 impairments of $14 million related to mature oil and gas producing assets in the U.S. onshore and Gulf of Mexico shelf areas. The impairment charges of $646 million in 2002 included $541 million for the Leadon field in the U.K. North Sea, $82 million for certain nonoperated North Sea fields and $23 million for several older Gulf of Mexico shelf properties. Negative reserve revisions stemming from additional performance analysis of these properties during 2002 resulted in revised estimates of future cash flows from the properties that were less than the carrying values of the related assets. For additional information regarding the Leadon field, see Note 25 to the Consolidated Financial Statements included in Item 8 of this annual report on Form 10-K.

The company recognized a net loss on sale of assets of $29 million in 2004. The loss was associated primarily with the conveyance of the company's interest in a nonproducing Gulf of Mexico field to another participating partner ($25 million), as well as losses of $6 million and gains of $2 million on sales of noncore properties in the Gulf of Mexico shelf and U.S. onshore areas. At December 31, 2004, the company had oil and gas properties with a carrying amount of $5 million classified as held-for-sale and, from time to time, may identify other oil and gas properties to be disposed of that are considered noncore or nearing the end of their productive lives.

In connection with the company's divestiture program initiated in 2002, certain oil and gas properties were identified for disposal and classified as held-for-sale properties. Upon classification as held-for-sale, the carrying value of the related properties is analyzed in relation to the estimated fair value less costs to sell, and losses are recognized if necessary. Upon ultimate disposal of the properties, any gain or additional loss on sale is recognized. Losses of $23 million and gains of $68 million were recognized in 2003 upon conclusion of the divestiture program in the U.S. and North Sea, and for the sale of the company's interests in the South China Sea (Liuhua field) and other noncore U.S. properties (onshore and Gulf of Mexico shelf areas). The company recognized losses of $176 million in 2002 associated with oil and gas properties held for sale in the U.S. (onshore and Gulf of Mexico shelf areas), the U.K. North Sea and Ecuador. Proceeds realized from these disposals totaled $119 million in 2003 and $374 million in 2002. The proceeds from the sale of these properties were used to reduce long-term debt.

Transportation Expense

Transportation expense, representing the costs paid to third-party providers to transport oil and gas production, increased by $17 million during 2004, to $111 million. The increase was due to additional transportation costs associated with the Westport assets ($11 million) and the new deepwater Gulf of Mexico Red Hawk and Gunnison fields. The increase was partially offset by lower costs in the North Sea due to lower sales volumes in 2004. On a per-unit basis, 2004 transportation expense was $.97 per boe compared to $.95 per boe in 2003.

Transportation costs in 2003 of $94 million were $10 million, or 12%, higher than 2002 as a result of higher costs associated with new deepwater Gulf of Mexico producing fields, partially offset by lower expense in the North Sea area.

General and Administrative Expense

General and administrative expense was $1.18 per boe for 2004, a decrease of $.11 per boe compared to 2003. Total 2004 general and administrative expense of $135 million was $8 million higher than 2003. Contributing to the increase was higher incentive compensation and pension costs, as well as additional administrative and personnel costs associated with the Westport merger ($8 million). The increase in 2004 was offset partially by lower costs as compared to 2003 associated with the workforce reduction program and the employee stock ownership plan.

General and administrative expense in 2003 was $40 million higher than in 2002. Of this increase, $23 million was due to employee severance and related costs attributed to the company's 2003 workforce reduction program and additional compensation expense associated with the employee stock purchase plan. Additionally, the company incurred higher costs in 2003 associated with pension and other employee benefits. These cost increases were offset partially by lower costs for direct labor and contract services.

Exploration Expense

(Millions of dollars)	**2004**	2003	2002
Exploration costs [(1)]	**$ 54**	$ 45	$ 36
Geological and geophysical costs	**86**	59	57
Dry hole expense	**161**	181	113
Amortization of undeveloped leases	**63**	69	67
Sales of unproved properties	**(8)**	–	–
Total exploration expense	**$356**	$354	$273

(1) Exploration costs include delay rentals, cost of retaining and carrying unproved properties and exploration department overhead.

In 2004, total exploration expense was $356 million, an increase of $2 million. Exploration activity associated with Westport assets contributed $36 million to exploration expense in 2004. Additionally, geological and geophysical data acquisition and processing costs increased in 2004 due to activity in the company's international areas, such as Brazil, Morocco and the Bahamas, as well as other new venture areas. Partially offsetting these increases were lower dry hole costs, lower amortization of undeveloped leases and a gain on sale of unproved properties. The gain on sale of unproved properties related primarily to reimbursement of past exploration costs by new partners purchasing an interest in our Morocco activities.

Exploration expense in 2003 was $81 million higher than in 2002 primarily as a result of higher dry hole costs from increased exploration activity during the year. In addition, staffing levels were increased during 2003 to support the company's worldwide exploration efforts and continued development of the company's high-potential prospect inventory.

Capitalized costs in our Consolidated Balance Sheet associated with exploratory wells may be charged to earnings in a future period if management determines that commercial quantities of hydrocarbons have not been discovered. At December 31, 2004, the company had capitalized costs of approximately $136 million associated with such ongoing exploration activities, primarily in the deepwater Gulf of Mexico, Brazil, Alaska and China. Additional information regarding deferred exploratory drilling costs is included in Note 31 to the Consolidated Financial Statements included in Item 8 of this annual report on Form 10-K.

Gas Marketing Activities

Kerr-McGee purchases third-party natural gas for aggregation and sale with the company's own production in the Rocky Mountain area. In addition, we have transportation capacity to markets in the Midwest to facilitate sale of natural gas outside the immediate vicinity of our production. This activity began with the company's acquisition of HS Resources in August 2001 and has increased since that time.

Marketing revenue was $419 million in 2004 and $298 million in 2003, an increase of $121 million and $228 million, respectively, as compared to the prior years. The increase in both 2004 and 2003 was the result of higher purchase and resale of third-party natural gas in the Rocky Mountain area and higher natural gas prices. Increased gas purchase costs of $127 million and $233 million in 2004 and 2003, respectively, more than offset the increase in revenues. Marketing volumes (thousand MMBtu/day) were 210 in 2004, 178 in 2003 and 77 in 2002.

CHEMICAL

Chemical segment revenues, operating profit (loss) and pigment production volumes are shown in the following table:

(Millions of dollars)	**2004**	2003	2002
Revenues –			
Pigment	**$1,209**	$1,079	$ 995
Other	**93**	78	70
Total	**$1,302**	$1,157	$1,065
Operating profit (loss) [(1)] –			
Pigment	**$ (80)**	$ (13)	$ 24
Other	**(1)**	(23)	(13)
Total	**$ (81)**	$ (36)	$ 11
Titanium dioxide pigment production (thousands of tonnes)	**549**	532	508

(1) Operating profit (loss) does not include litigation provisions and environmental provisions, net of reimbursements, related to various businesses in which the company's affiliates are no longer engaged, such as the mining and processing of uranium and thorium and other businesses.

Operating profit (loss) for all periods presented included certain items affecting comparability between periods. Because of their nature and amount, these items are identified separately to help explain the changes in operating profit (loss) between periods, as well as to help distinguish the underlying trends for the segment's core businesses. These items are listed in the following table and, to the extent material, are discussed in the analysis of operating profit that follows:

(Millions of dollars)	**2004**	2003	2002
Included in Chemical - Pigment Operating Profit (Loss):			
Plant shutdown costs and accelerated depreciation	**$(122)**	$(44)	$(12)
Asset impairments	**(8)**	–	–
Insurance premium adjustment	**(4)**	–	–
Environmental provisions	**(1)**	(1)	5
Cost associated with the 2003 work force reduction program	**(1)**	(18)	–
Compensation expense for allocated ESOP shares	**–**	(5)	–
Other	**4**	1	(2)
Included in Chemical - Other Operating Loss:			
Plant shutdown costs and accelerated depreciation	**–**	(1)	–
Environmental provisions	**(3)**	(12)	(15)
Cost associated with the 2003 work force reduction program	**–**	(3)	–
Compensation expense for allocated ESOP shares	**–**	(1)	–
Total items affecting comparability	**$(135)**	$(84)	$(24)

Chemical - Pigment – Revenues increased $130 million, or 12%, in 2004 to $1.209 billion from $1.079 billion in 2003. Of the total increase, $114 million was due to increased sales volumes and $16 million resulted from an increase in average sales prices. Sales volumes for 2004 were approximately 9% higher than in the prior year due primarily to strong market conditions. Approximately half of the increase in average sales prices in 2004 was due to the effect of foreign currency exchange rates and the remainder due to price increases resulting from improved market conditions.

Revenues increased $84 million, or 8%, in 2003 to $1.079 billion from $995 million in 2002. Of the total increase, $94 million resulted from an increase in average sales prices, partially offset by a $10 million decrease due to lower sales volumes. The increase in average sales prices in 2003 was largely due to the effect of foreign currency exchange rates. Excluding the effect of foreign currency exchange rates, average selling prices in local currencies for 2003 were 3% higher than in 2002. Sales volumes for 2003 were approximately 1% lower than in the prior year.

The chemical - pigment operating unit recorded an operating loss of $80 million in 2004, compared with an operating loss of $13 million in 2003. The 2004 operating loss was primarily the result of shutdown provisions totaling $105 million (including an $8 million charge for asset impairment) for the sulfate-process titanium dioxide pigment production at the Savannah, Georgia, facility and additional charges at that facility of $18 million for accelerated depreciation of other plant assets that are no longer in service. In addition, operating results for 2004 were negatively impacted by $7 million of costs incurred in connection with the continued efforts to close the synthetic rutile plant in Mobile, Alabama, compared to a $47 million plant closure provision recognized in 2003 for this facility. Additionally, operating results in 2003 were negatively impacted by a $23 million charge for work force reduction and other compensation costs. These charges had the effect of reducing operating profit by $130 million in 2004 and $70 million in 2003. The $130 million increase in revenues in 2004 resulting from higher volume and sales prices was offset by an increase of $125 million in production costs due to higher volume ($73 million) and costs ($52 million including the effects of foreign currency exchange rate changes) and an increase in shipping and handling costs and selling, general and administrative expenses of $13 million over 2003. Additional information related to the shutdowns of the Savannah and Mobile facilities is included in Note 13 to the Consolidated Financial Statements included in item 8 of this annual report on Form 10-K.

The chemical - pigment operating unit recorded an operating loss of $13 million in 2003, compared with operating profit of $24 million in 2002. The $94 million increase in revenues due to higher sales prices was partially offset by an increase in average product costs of $51 million and an increase in shipping and handling costs and selling, general and administrative costs of $18 million over 2002. Additionally, operating results in 2003 were impacted by $47 million in plant closure provisions related to the synthetic rutile plant in Mobile, Alabama, together with a $23 million charge for work force reduction and other compensation costs. The $47 million shutdown provision for the Mobile operations included $6 million for curtailment costs related to pension and postretirement benefits. The 2002 operating profit included $12 million in charges for abandoned chemical engineering projects, $3 million for severance and other costs and a $5 million reversal of environmental reserves associated with the Savannah operations.

During 2004, the company continued to operate its new high-productivity oxidation line for chloride-process titanium dioxide pigment production at the Savannah facility. This project, if successful, will substantially increase chloride production capability at a reduced asset intensity level. The company continues to evaluate the performance of this new oxidation line and expects to have a better understanding of how the Savannah site might be reconfigured to exploit its capabilities in 2005. The possible reconfiguration of the Savannah site, if any, could include redeployment of certain assets, idling of certain assets and reduction of the future useful life of certain assets, resulting in the acceleration of depreciation expense and the recognition of other charges.

Chemical - Other – Operating loss for 2004 was $1 million on revenues of $93 million, compared with operating loss of $23 million on revenues of $78 million in 2003. The increase in revenues of $15 million was primarily due to an increase in electrolytic sales due primarily to the full year of operations at the company's electrolytic manganese dioxide (EMD) manufacturing operation in Henderson, Nevada (see further discussion below). Improved operating performance was primarily due to the full year of operations at the EMD facility, lower environmental costs in 2004 of $9 million compared to 2003 and the work force reduction and other compensation charges recognized in 2003 that did not reoccur in 2004.

Operating loss for 2003 was $23 million on revenues of $78 million, compared with operating loss of $13 million on revenues of $70 million in 2002. The increase in sales was due to higher electrolytic operations sales volumes. The increased volumes were predominantly achieved in sodium chlorate and boron products, 17% and 37%, respectively. The $10 million increase in operating loss for 2003 was primarily due to 2003 work force reduction costs and other compensation charges of $4 million and higher electrolytic product costs of $8 million, partially offset by lower environmental costs of $3 million. Environmental provisions in both 2003 and 2002 related primarily to ammonium perchlorate remediation associated with the company's Henderson, Nevada, operations (see Note 19 to the Consolidated Financial Statements included in Item 8 of this annual report on form 10-K).

In 2002, the company announced plans to exit the forest products business and four of the company's five wood-treatment facilities were closed during 2003. The fifth plant, which was a leased facility, ceased all significant operations by the end of 2004 and the assets were sold in January 2005.

During the third quarter of 2003, Kerr-McGee Chemical LLC placed its EMD manufacturing operation in Henderson, Nevada, on standby to reduce inventory levels because of the harmful effect of low-priced imports on the company's EMD business. In response to the pricing activities of importing companies, Kerr-McGee Chemical LLC filed a petition for the imposition of anti-dumping duties with the U.S. Department of Commerce International Trade Administration and the U.S. International Trade Commission on July 31, 2003. In its petition, the company alleged that manufacturers in certain countries export EMD to the United States in violation of the U.S. anti-dumping laws and requested that the U.S. Department of Commerce apply anti-dumping duties to the EMD imported from such countries. The Department of Commerce found probable cause to believe that manufacturers in the specified countries engaged in dumping and initiated an anti-dumping investigation with respect to such manufacturers. Partly as a result of the anti-dumping petition, demand for U.S. EMD product increased, and the plant resumed operations in December 2003. The company withdrew its anti-dumping petition in February 2004 but continues to monitor market conditions.

Financial Condition

The following table provides certain information useful in analysis of the company's financial condition at December 31, 2004, 2003 and 2002.

(Millions of dollars)	**2004**	2003	2002
Current ratio [1]	**0.8 to 1**	0.8 to 1	0.8 to 1
Total debt	**$3,699**	$3,655	$3,904
Total debt less DECS [2]	**3,699**	3,329	3,586
Stockholders' equity	**$5,318**	$2,636	$2,536
Debt to total capitalization [3]	**41%**	58%	61%
Total debt less DECS to total capitalization [2] [3]	**41%**	56%	59%
Floating-rate debt to total debt (fixed-rate debt with interest rate swaps to variable rate is treated as floating rate debt)	**25%**	14%	16%

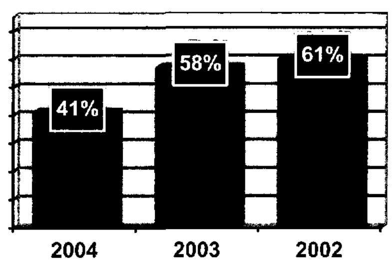
(1) Represents a ratio of current assets to current liabilities.

(2) Under the terms of the company's debt exchangeable for stock (DECS) which matured on August 2, 2004, we had an option to redeem our debt obligation by distributing shares of Devon Energy Corporation (Devon) common stock to the debt holders. The DECS were redeemed at maturity through the distribution of Devon stock. Certain ratios and measures are provided excluding the effect of DECS balances at December 31, 2003 and 2002 to demonstrate the effect on our financial condition of debt obligations that require the use of cash. Additional information regarding the DECS and their redemption is included in Note 7 to the Consolidated Financial Statements included in item 8 of this annual report on Form 10-K.

(3) Capitalization is determined as total debt or total debt less DECS, as applicable, plus total stockholders' equity.

Debt to Total Capitalization

Debt to total capitalization is total debt divided by total debt plus stockholders' equity.



During 2004, we reduced the percentage of total debt to total capitalization from 58% to 41%, despite the assumption of approximately $1.0 billion of debt in the Westport merger. Activities contributing to this change in the leverage ratio are outlined below.

- Westport debt assumed in the merger was repaid shortly after completing the merger with net proceeds from the issuance of $650 million principal amount of 6.95% notes due 2024 and borrowings under our revolving credit facility.
- In connection with the merger, we issued 48.9 million shares of common stock to former Westport shareholders, increasing stockholders' equity by $2.4 billion.
- Net income exceeded dividends declared, increasing equity by $176 million.
- In addition to repaying Westport debt, we reduced total debt by $577 million, including the redemption of $330 million principal amount of DECS through distribution of Devon shares.

Kerr-McGee operates with the philosophy that over a five-year plan period the company's capital expenditures and dividends should be funded by cash generated from operations. On a cumulative basis, the cash generated from operations for the past five years has exceeded the company's capital expenditures (excluding cash spent for acquisitions) and dividend payments. Debt and equity transactions are utilized for acquisition opportunities and short-term needs due to timing of cash flow.

The company's future debt level depends on our future results of operations, our capital expenditure program, and requirements for and sources of cash associated with asset acquisitions and dispositions. Discussion on the company's borrowing capacity available to meet unanticipated cash requirements is included in the *Liquidity* section below.

In February 2005, we called for redemption all of the $600 million aggregate principal amount of our 5.25% convertible subordinated debentures due 2010 at a price of 102.625%. Prior to March 4, 2005, the redemption date, all of the debentures were converted by the holders into approximately 9.8 million shares of common stock. As a result of this conversion, the number of total common shares outstanding increased to approximately 162 million. Pro forma for the conversion, our year-end 2004 total debt to total capitalization ratio would have been 34%.

On March 8, 2005, the company's Board of Directors (the Board) authorized the company to proceed with a share repurchase program initially set at $1 billion. The Board expects to expand the share repurchase program as the chemical business separation proceeds. The initial $1 billion share repurchase program primarily will be financed through the use of free cash flow generated from operations after planned capital expenditures, which is projected to be approximately $850 million in 2005. The company also expects to utilize a portion of its existing bank credit facility and may issue new securities, which may be in the form of debt or perpetual preferred stock, to fund the remaining repurchase program. The company still intends to retire $450 million of debt maturities due in 2005 in addition to the conversion of subordinated debentures discussed above. The Board and management reiterated their commitment to maintain an investment-grade credit rating.

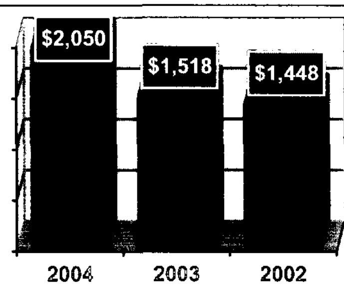
The timing and final number of shares to be repurchased under an expanded repurchase program will depend on the outcome of the chemical business separation, as well as business and market conditions, applicable securities law limitations and other factors. Shares may be purchased from time to time in the open market or through privately negotiated transactions at prevailing prices, and the program may be suspended or discontinued at any time without prior notice.

Cash Flows

We rely on cash flows from operating activities as a primary source of liquidity. As necessary, this source has been supplemented by accessing credit lines and commercial paper markets and issuing equity and debt securities.

Cash Flows from Operating Activities
(Millions of dollars)

Cash flows from operating activities has increased significantly over the past two years primarily due to increased oil and gas prices and production.



Cash Flows from Operating Activities - Cash flows from operating activities increased by $532 million, from $1.5 billion in 2003 to $2.1 billion in 2004. Our merger with Westport in June 2004 contributed to an increase in oil and gas production on a barrel of oil equivalent basis of 15% over 2003. Average prices realized upon the sale of oil and gas, including hedging activities, increased by 13%. The combined effect of these factors contributed significantly to the 2004 increase in cash flows from operating activities. Additionally, in 2004, our environmental cash expenditures, net of reimbursements received, were lower compared to the prior year. These positive effects on cash flows from operating activities were partially offset by higher contributions made to postretirement and pension plans and higher expenditures for operating costs primarily due to the Westport merger.

Cash Used in Investing Activities - Including dry hole costs, we invested $1.3 billion, $1.2 billion and $1.3 billion in our capital program in 2004, 2003 and 2002, respectively. The $178 million increase in capital expenditures and dry hole costs in 2004 was primarily related to higher spending onshore in the U.S., where our drilling program was expanded following the Westport merger. The capital program for 2003 was $110 million lower than in the prior year, resulting primarily from lower capital expenditures in the North Sea and U.S. onshore regions, partially offset by higher capital expenditures in the Gulf of Mexico and China and higher dry hole costs.

Our merger with Westport was financed by issuing common stock and assuming Westport's debt obligations and, therefore, did not affect investing cash flows, except for Westport cash balances of $43 million acquired in the merger. During 2003, we invested $110 million in selected oil and gas property acquisitions for an additional interest in the U.K. Gryphon and South Gryphon fields and an onshore property acquisition in South Texas. Additionally, in 2003, we completed the divestiture of several oil and gas properties and other assets, generating proceeds of $304 million. These proceeds were used primarily to pay down debt. Cash outlays for investing activities during 2004, 2003 and 2002 include investment by the chemical unit in Avestor, its lithium-metal-polymer battery joint venture in Canada, of $25 million, $34 million and $47 million, respectively. Other investing cash inflows included $39 million in 2004 and $47 million in 2003 in proceeds related to the sale of Devon stock. By the end of 2004, all of the shares of Devon common stock were disposed of either through sale or in settlement of our DECS obligation discussed in the *Financial Condition* section above.

Cash Used in Financing Activities - In 2004, we repaid $1.3 billion of debt, including debt assumed in the Westport merger. The $245 million balance outstanding under the Westport revolving credit facility at the date of the merger was repaid upon completion of the merger and the facility was terminated on July 13, 2004. We also redeemed the 8.25% Westport notes assumed in the merger for $786 million (including a make-whole premium of $100 million) and repaid $247 million in 2004 for scheduled repayments and maturities of our debt. On July 1, 2004, we issued 6.95% notes due 2024 for net proceeds of $636 million. Proceeds from the notes issuance were used to redeem the 8.25% Westport notes discussed above. In 2004, we also paid $101 million to settle derivative liabilities assumed from Westport. Dividends paid in 2004 were $205 million, an increase of $24 million compared to 2003. This increase primarily resulted from the issuance of 48.9 million shares of our common stock in the Westport merger. We received proceeds from employee stock option exercises of $55 million in 2004 with more stock option exercises compared to prior years as a result of the Westport merger and the increasing price of our common stock.

Liquidity

The company believes that it has the ability to provide for its operational needs and its long- and short-term capital programs through its cash flows from operating activities, borrowing capacity and ability to raise capital. The company's primary source of funds has been from operating cash flows, which could be adversely affected by declines in oil, natural gas and pigment prices, all of which can be volatile, as discussed under *Operating Environment and Outlook*. Our hedging program is intended to partially mitigate variability in operating cash flows caused by fluctuations in oil and natural gas prices. At December 31, 2004, commodity derivatives covered approximately 50% of our projected 2005 oil and gas production. The portion of our projected production subject to commodity derivative instruments is determined by management and may change in future periods in response to market conditions and our operational needs. If operating cash flows decline, the company may reduce its capital expenditures program, borrow under its commercial paper program, draw upon its revolving credit facility and/or consider selective long-term borrowings or equity issuances. Our commercial paper programs are backed by the revolving credit facility currently in place.

In November 2004, the company entered into a $1.5 billion unsecured revolving credit agreement with a term of five years. Concurrent with this transaction, we terminated two revolving credit facilities with an aggregate maximum availability of $1.35 billion. A portion of the $1.5 billion revolving credit facility can be used to support commercial paper borrowings in the U.S. and Europe by certain wholly-owned subsidiaries and are guaranteed by the parent company. Borrowings under the credit agreement can be made in U.S. dollars, British pound sterling and euros. Interest on borrowings under the new revolving credit facility may be based, at the company's option, on LIBOR, EURIBOR or on the JPMorgan prime rate. The interest rate margin varies based on facility utilization and the company's debt rating, utilizing the two highest of the company's senior unsecured debt ratings by Moody's, Standard and Poor's (S&P), and Fitch in determining the spread above the applicable interest rate index. At year-end 2004, the company had a maximum available capacity under the revolving credit facility and bank lines of credit of $1.55 billion and $41 million outstanding in commercial paper borrowings.

At December 31, 2004, the company classified its $41 million of short-term commercial paper borrowings as long-term debt based on its ability and intent, as evidenced by committed credit agreements, to refinance this debt on a long-term basis. The company's practice has been to continually refinance its commercial paper or draw on its backup facilities, while maintaining borrowing levels believed to be appropriate. Additional information on the company's debt is included in Note 14 to the Consolidated Financial Statements included in Item 8 of this annual report on Form 10-K.

The company has available, to issue and sell, a total of $1 billion of debt securities, common or preferred stock, or warrants under its shelf registration with the Securities and Exchange Commission, which was last updated in February 2002.

Additionally, the company maintains an accounts receivable monetization program, which provides an additional source of liquidity up to a maximum of $165 million. This program is discussed in detail in the *Off-Balance Sheet Arrangements* section that follows.

The company had negative working capital at the end of 2004; however, that is not indicative of a lack of liquidity as the company maintains sufficient current assets to settle current liabilities when due. Cash balances are minimized as one way to finance capital expenditures and lower borrowing costs. Additionally, our working capital position is affected by current assets and liabilities associated with our financial derivatives. At December 31, 2004, the company had recorded approximately $300 million of net current derivative liabilities for contracts that will effectively adjust the cash flows to be realized upon the sale of our future oil and gas production and chemical products. Because those sales have not yet occurred, the associated accounts receivable are not yet reflected in our Consolidated Balance Sheet, while derivative assets and liabilities are carried on the Consolidated Balance Sheet at their estimated fair value. Because of the high degree of volatility in oil and natural gas commodity markets, our working capital position will be continually affected by changes in the fair value of derivative instruments.

Certain of our derivative financial instruments require margin deposits if unrealized losses exceed limits established with individual counterparty institutions. From time to time, we may be required to advance cash to our counterparties to satisfy margin deposit requirements. No margin deposits were outstanding at December 31, 2004.

Our long-term debt agreements do not contain subjective acceleration clauses (commonly referred to as material adverse change clauses); however, certain of our long-term debt agreements contain restrictive covenants, including a maximum total debt to total capitalization ratio, as defined in the agreements, of 65%. At December 31, 2004, the company had a total debt to capitalization ratio of 41% and was in compliance with its other debt covenants. As discussed under *Financial Condition* above, $600 million of our 5.25% convertible subordinated debentures were converted to common stock in March 2005. Pro forma for the conversion, our year-end 2004 total debt to total capitalization ratio would have been 34%.

As of December 31, 2004, the company's senior unsecured debt was rated BBB by S&P and Fitch and Baa3 by Moody's. In March 2005, Moody's, S&P and Fitch each issued a press release indicating the company was under review for a possible downgrade. The rating agency announcements were primarily in response to a recent shareholder proposal to execute a large share repurchase program using proceeds from a volumetric production payment (VPP). The Board rejected the VPP proposal as irresponsible and not in the best interests of stockholders, creditors and the company. The Board of Directors did, however, approve a $1 billion share repurchase program on March 8, 2005, as discussed in *Financial Condition* above. Following the company's announcement of the share repurchase program, S&P lowered the company's credit rating from BBB to BBB –. The downgrade by S&P will result in a 15 basis-point increase in borrowing costs under our revolving credit facility. In rating the company's debt, the agencies consider our financial and operating risk profile by analyzing our debt levels, growth profile, cost structure, oil and gas reserve replacement ratios, capital expenditure requirements, contingencies, dividend policy and any other factors they deem relevant that could potentially impact our ability to service our debt. Should the company's commercial paper or debt ratings be further downgraded, borrowing costs will increase, and the company may experience a loss of investor interest in its debt instruments as evidenced by a reduction in the number of investors and/or amounts they are willing to invest. If two of the three rating agencies lowered the company's debt rating to BB+ or Ba1, the company's borrowing costs would increase 55 basis points from year-end levels. As discussed in the *Off-Balance Sheet Arrangements* section that follows, ratings downgrade below specified levels would result in modifications to or termination of our accounts receivable monetization program. In connection with the March 8, 2005 share repurchase program announcement, the company's Board and management reiterated their commitment to maintain an investment-grade credit rating.

Off-Balance Sheet Arrangements

During 2001 and 2000, the company identified certain financing needs that it determined would be best handled by off-balance sheet arrangements with unconsolidated, special-purpose entities. Three leasing arrangements were entered into for financing the company's working interest obligations for production platforms and related equipment at three company-operated fields in the Gulf of Mexico. Also, the company entered into an accounts receivable monetization program to sell its receivables from certain pigment customers. Each of these transactions has provided specific financing for the company's business needs and/or projects and does not expose the company to significant additional risks or commitments. The leases have provided a tax-efficient method of financing a portion of these major development projects, and the sale of the pigment receivables offers an attractive low-cost source of liquidity.

Spar Platform Leases - During 2001, the company entered into a leasing arrangement for its interest in the production platform and related equipment for the Gunnison field in the Garden Banks area of the Gulf of Mexico. This leasing arrangement is similar to two arrangements entered into in 2000 for the Nansen and Boomvang fields in the East Breaks area of the Gulf of Mexico. In each of these three arrangements, the company entered into lease commitments with separate business trusts that were created to construct independent spar production platforms for each field development. Under the terms of the agreements, the company's share of construction costs for the platforms was initially financed by synthetic lease credit facilities between the trust and groups of financial institutions for $149 million, $137 million and $78 million for Gunnison, Nansen and Boomvang, respectively, with the company making lease payments sufficient to pay interest at varying rates on the financings. Upon completion of the construction phase, separate business trusts with third-party equity participants acquired the assets and became the lessor/owner of the platforms and related equipment. The company and these trusts have entered into operating leases for the use of the spar platforms and related equipment. During 2002, the Nansen and Boomvang synthetic leases were converted to operating lease arrangements upon completion of construction of the respective production platforms. Completion of the Gunnison platform occurred in December 2003, at which time a portion of the Gunnison synthetic lease was converted to an operating lease. The remaining portion of the Gunnison synthetic lease was converted to an operating lease on January 15, 2004. Under this type of financing structure, the company leases the platforms under operating lease agreements, and neither the platform assets nor the related debt is recognized in the company's Consolidated Balance Sheet. However, since only a portion of the Gunnison synthetic lease had been converted to an operating lease structure as of December 31, 2003, the remaining assets and liabilities of the synthetic lessor trust were included in the company's Consolidated Balance Sheet at December 31, 2003. Since the remaining portion of the Gunnison synthetic lease was converted to an operating lease structure in January 2004, the platform assets and related debt are not included in our Consolidated Balance Sheet at December 31, 2004. For additional information regarding Gunnison trust consolidation see Note 14 to the Consolidated Financial Statements included in Item 8 of this annual report on Form 10-K.

In conjunction with the operating lease agreements, the company has guaranteed that the residual values of the Nansen, Boomvang and Gunnison platforms at the end of the operating leases shall be equal to at least 10% of their fair market value at the inception of the lease. For Nansen and Boomvang, the guaranteed values are $14 million and $8 million, respectively, in 2022, and for Gunnison the guaranteed value is $15 million in 2024. Estimated future minimum annual rentals under these leases and the residual value guarantees are shown in the table of contractual obligations below.

Accounts Receivable Monetization Program - In December 2000, the company began an accounts receivable monetization program for its pigment business through the sale of selected accounts receivable with a three-year, credit-insurance-backed asset securitization program. On July 30, 2003, the company restructured the existing accounts receivable monetization program to include the sale of receivables originated by the company's European chemical operations. During the third quarter of 2004, the company completed its renewal of the program, extending the term through July 27, 2005. The maximum availability under the program is $165 million. Under the terms of the program, selected qualifying customer accounts receivable are sold monthly to a special-purpose entity (SPE), which in turn sells an undivided ownership interest in the receivables to a third-party multi-seller commercial paper conduit sponsored by an independent financial institution. The company sells, and retains an interest in, excess receivables to the SPE as over-collateralization for the program. The company's retained interest in the SPE's receivables is classified in trade accounts receivable in the accompanying Consolidated Balance Sheet. The retained interest is subordinate to, and provides credit enhancement for, the conduit's ownership interest in the SPE's receivables, and is available to the conduit to pay certain fees or expenses due to the conduit, and to absorb credit losses incurred on any of the SPE's receivables in the event of termination. However, the company believes that the risk of credit loss is very low since its bad-debt experience has historically been insignificant. The company retains servicing responsibilities and receives a servicing fee of 1.07% of the receivables sold for the period of time outstanding, generally 60 to 120 days. No recourse obligations were recorded since the company has no obligations for any recourse actions on the sold receivables. The company also holds preference stock in the SPE, which essentially represents a retained deposit to provide further credit enhancements, if needed, but otherwise is recoverable by the company at the end of the program. The carrying value of our investment in the preference stock was $4 million at December 31, 2004 and 2003.

The program includes a ratings downgrade trigger in the event Kerr-McGee's corporate senior unsecured debt rating falls below BBB- by S&P or Baa3 by Moody's, or in the event such rating has been suspended or withdrawn by S&P or Moody's. The result of the downgrade trigger is an increase in the cost of the program, along with other program modifications. In addition, the program includes a ratings downgrade termination event, upon which the program effectively liquidates over time and the third-party multi-seller commercial paper conduit is repaid by the collections on accounts receivable sold by the SPE. The ratings downgrade termination event is triggered if Kerr-McGee's corporate senior unsecured debt (i) is rated less than BBB- by S&P and Baa3 by Moody's, (ii) is rated less than BB+ by S&P or Ba1 by Moody's or (iii) is withdrawn or suspended by S&P or Moody's. At year-end 2004 and 2003, the outstanding balance on receivables sold under the program totaled $165 million.

Sale-Leaseback Transactions - During 2003 and 2002, the company entered into sale-leaseback arrangements with General Electric Capital Corporation (GECC) covering assets associated with a gas-gathering system in the Wattenberg field. The lease agreements were entered into for the purpose of monetizing certain of the gathering system assets. The sales price for the 2003 equipment was $6 million. The sales price for the 2002 equipment was $71 million; however, an $18 million settlement obligation existed for equipment previously covered by the lease agreement, resulting in net cash proceeds of $53 million in 2002. The 2002 operating lease agreements have an initial term of five years, with two 12-month renewal options, and the company may elect to purchase the equipment at specified amounts after the end of the fourth year. The 2003 operating lease agreement has an initial term of four years, with two 12-month renewal options. In the event the company does not purchase the equipment and it is returned to GECC, the company guarantees a residual value ranging from $35 million at the end of the initial terms to $27 million at the end of the last renewal option. The company recorded no gain or loss associated with the GECC sale-leaseback agreements. Estimated future minimum annual rentals under this agreement and the residual value guarantee are shown in the table of contractual obligations below.

Other Arrangements - In conjunction with the company's 2002 sale of its Ecuadorean assets, which included the company's nonoperating interest in the Oleoducto de Crudos Pesados Ltd. (OCP) pipeline, the company entered into a performance guarantee agreement with the buyer for the benefit of OCP. Execution of the guarantee by Kerr-McGee was required to obtain the necessary cooperation and consents from OCP to close the company's sale of its Ecuadorean assets. Under the terms of the agreement, the company guarantees payment of any claims from OCP against the buyer upon default by the buyer and its parent company. Claims would generally be for the buyer's proportionate share of construction costs of OCP; however, other claims may arise in the normal operations of the pipeline. Accordingly, the amount of any such future claims cannot be reasonably estimated. In connection with this guarantee, the buyer's parent company has issued a letter of credit in favor of the company up to a maximum of $50 million, upon which the company can draw in the event it is required to perform under the guarantee agreement. The company will be released from this guarantee when the buyer obtains a specified credit rating as stipulated under the guarantee agreement.

In addition, the company has entered into certain indemnification agreements related to title claims, environmental matters, litigation and other claims. The company has recorded no material obligations in connection with its indemnification agreements. At December 31, 2004, the company had outstanding letters of credit in the amount of approximately $106 million. Most of these letters of credit have been granted by financial institutions to support our international drilling commitments.

Obligations and Commitments

In the normal course of business, the company enters into purchase obligations, contracts, leases and borrowing arrangements. The company has no debt guarantees for third parties. As part of the company's project-oriented exploration and production business, we routinely enter into contracts for certain aspects of a project, such as engineering, drilling, subsea work, etc. These contracts are generally not unconditional obligations; thus, the company accrues for the value of work done at any point in time, a portion of which is billed to partners. Kerr-McGee's commitments and obligations as of December 31, 2004, are summarized in the following table:

(Millions of dollars)	Payments due by period				
Type of Obligation	Total	2005	2006 -2007	2008 -2009	After 2009
Long-term debt, including current portion [1]	$3,783	$ 460	$ 457	$ 41	$2,825
Operating leases for Nansen, Boomvang and Gunnison	582	23	54	55	450
All other operating leases	241	46	72	54	69
Drilling rig commitments	117	117	–	–	–
Purchase obligations –					
Ore contracts	387	156	191	40	–
Gas purchase and transportation contracts	222	32	55	46	89
Other purchase obligations	511	221	219	38	33
Leased equipment residual value guarantees	72	–	–	35	37
Total	$5,915	$1,055	$1,048	$309	$3,503

(1) Principal amounts represent future payments and exclude the unamortized discount on issuance of $85 million and the net fair value hedge adjustments of $(1) million.

Capital Spending

Capital expenditures are summarized as follows:

(Millions of dollars)	Est. 2005	2004	2003	2002
Exploration and production, including dry hole costs	$1,919	$1,230	$1,050	$1,101
Chemical	100	92	97	85
Other, including discontinued operations	25	18	15	86
Total	$2,044	$1,340	$1,162	$1,272

Capital spending, excluding acquisitions, totaled $3.8 billion in the three-year period ended December 31, 2004, and dividends paid totaled $567 million in the same three-year period, which compares with $5 billion of net cash provided by operating activities during the same period.

Kerr-McGee has budgeted approximately $2 billion for its capital program in 2005. Management anticipates that the 2005 capital program, dividends and debt reduction can be provided for through internally generated funds. Available borrowing capacity may be used for selective acquisitions that support the company's growth strategy or to support the company's capital expenditure program should internally generated cash flow fall short in any particular year.

Exploration and Production

Our merger with Westport during 2004 provided a substantial inventory of low-risk onshore exploitation opportunities, particularly in the Rocky Mountain area. The company plans to capitalize on these opportunities in 2005 with a $430 million development drilling program in the Rocky Mountain area, focusing primarily on the Greater Natural Buttes and Wattenberg fields. In the Southern area of the U.S. onshore region, the Westport merger also resulted in a significant increase in the company's inventory of attractive investment opportunities. As a result, we plan to invest about $230 million in the Southern area primarily for development drilling in South Texas, the Mid-Continent/Permian Basin and Gulf Coast regions. Capital expenditures onshore in the U.S. will total about $660 million in 2005.

In the Gulf of Mexico, the company plans to invest $645 million in 2005. About one-third of our planned Gulf of Mexico capital expenditures will be investment at the Constitution/Ticonderoga development on Green Canyon 680/768 where first production is expected in mid-2006. Other Gulf of Mexico investments will focus on subsea development of our Atwater Valley discoveries at Merganser, Vortex and San Jacinto, as well as other satellite exploitation, infill drilling and recompletion investments around existing infrastructure.

In the North Sea region, we plan capital expenditures of about $270 million for 2005. The 2005 program for the North Sea will focus primarily on infill drilling at the company-operated Gryphon and Janice fields, as well as other non-operated fields. In the international and new ventures areas, we plan to invest about $160 million in 2005. This investment will be focused primarily on the completion of the initial development drilling program at the CFD 11-1/2 fields in Bohai Bay, China, as well as expected development costs at the CFD 11-3/5, CFD 11-6 and CFD 12-1/12-1S fields.

Including about $9 million for investment in information systems technology, the company's 2005 capital budget for its exploration and production business totals about $1.7 billion. In addition, the company has budgeted expenditures of approximately $305 million (excluding noncash amortization of nonproducing leasehold costs) for exploration expense in 2005, including $175 million for dry hole costs. The company's exploration program is expected to fund approximately 100 exploratory and appraisal wells, with emphasis on balancing risks and potential rewards in both shallow and deep waters and onshore in the U.S.

Chemical

Capital expenditures for chemical operations are budgeted at $100 million for 2005. Process and technology improvements that increase productivity and enhance product quality will account for approximately 43% of the 2005 capital budget. This includes changes to the front-end process at the Uergingen, Germany pigment facility to convert waste to a saleable product and reduce raw material costs and upgrading the oxidation line at the Botlek, Netherlands, pigment facility to improve throughput. Chemical has also budgeted $45 million of additional investment in Avestor for 2005.

Market Risks

The company is exposed to a variety of market risks, including credit risk, changes in oil and gas commodity prices, foreign currency exchange rates and interest rates. We address these risks through a controlled program of risk management that includes the use of insurance and derivative financial instruments. In addition to information included in this section, see Notes 1 and 11 to the Consolidated Financial Statements included in Item 8 of this annual report on Form 10-K for discussions of the company's derivatives and hedging activities.

Commodity Price Risk

Our oil and natural gas production is generally sold at prevailing market prices, thus exposing us to the risk of variability of our revenues and operating cash flows. To reduce the impact of these risks on earnings and to increase the predictability of its cash flows, the company enters into certain derivative instruments that generally fix the commodity prices to be received for a portion of its future oil and gas production. The company utilizes derivative instruments as a means of balancing cash flow requirements for debt repayment and its capital programs. At December 31, 2004, commodity derivatives covered approximately 50% of our projected 2005 oil and gas production, a decline from approximately 75% for 2004. A lower hedge ratio allows us to benefit from increases in market prices for oil and natural gas, if they occur, but also exposes us to a greater possibility of lower realized prices, should commodity prices decline. A risk management committee consisting of senior executives, including the CEO, develops the company's hedging strategy. In setting hedge targets, the committee evaluates various factors, including debt management targets, liquidity, exploration and development opportunities, cash flow modeling under various price scenarios and the overall growth strategy for the company. These and other factors are used to formulate specific hedge targets on an ongoing basis.

At December 31, 2004, outstanding commodity-related derivatives had a net liability fair value of $494 million. The fair value of these derivative instruments was determined based on prices actively quoted, generally NYMEX and Dated Brent prices. For derivative instruments designated as cash flow hedges, gains and losses are deferred in accumulated other comprehensive income (loss) and reclassified into earnings when the associated hedged production is sold, except for gains or losses resulting from hedge ineffectiveness, which are recognized as incurred. Realized and unrealized gains and losses arising from derivative instruments not designated as hedges or that do not qualify for hedge accounting (nonhedge derivatives) are recognized in earnings currently. At December 31, 2004, the company had after-tax deferred losses of $174 million in accumulated other comprehensive income (loss) associated with oil and gas cash flow hedges. We expect to reclassify $52 million of these losses into earnings during the next 12 months, assuming no further changes in fair value of the contracts. Net realized oil and gas hedging losses totaled $748 million, $279 million and $81 million in 2004, 2003 and 2002, respectively. The losses offset the higher oil and natural gas prices realized on the physical sale of crude oil and natural gas. Average realized oil and gas sales prices excluding and including the effect of our hedging program are presented above under *Results of Operations by Segment – Exploration and Production*. Gains and losses for hedge ineffectiveness for all periods presented were not material.

The following summary provides information about outstanding commodity-related derivative contracts that have been designated as hedges at December 31, 2004:

Contract Type [1]	Period	Average Daily Volume	Average Contract Price
Natural Gas Hedges		**MMBtu**	**$/MMBtu**
Fixed-price swaps (NYMEX)	2005	55,000	$4.42
	Q2, Q3 - 2005	75,000	$6.48
	Q4 - 2005	25,272	$6.48
Costless collars (NYMEX)	Q1 - 2005	225,000	$6.50 - $10.31
	Q2, Q3 - 2005	75,000	$6.00 - $ 7.86
	Q4 - 2005	25,272	$6.00 - $ 7.86
	2005	280,000	$5.00 - $ 6.25
	2006	340,000	$4.75 - $ 5.50
Basis swaps (CIG) [2]	2005	20,000	$0.39
Basis swaps (NWPRM) [3]	2005	25,000	$0.43
Crude Oil Hedges		**Barrel**	**$/Barrel**
Fixed-price swaps (WTI)	2005	3,000	$29.23
Fixed-price swaps (Brent)	2005	16,000	$41.03
Costless collars (WTI)	2005	5,500	$40.00 - $49.80
	2005	14,000	$28.50 - $31.89
	2006	19,000	$27.00 - $30.58
Costless collars (Brent)	2005	10,500	$38.00 - $48.12

(1) These contracts may be subject to margin calls above certain limits established with individual counterparty institutions.

(2) Colorado Interstate Gas pipeline.

(3) Northwest Pipeline Rocky Mountain index.

The company holds certain gas basis swaps settling between 2005 and 2008 that were acquired in the 2001 merger with HS Resources. The company initially treated these gas basis swaps as nonhedge derivatives, with changes in fair value recognized in earnings. In 2004, the company designated those swaps settling in 2005 as hedges, since the basis swaps have been coupled with natural gas fixed-price swaps, while the remainder settling between 2006 and 2008 will continue to be treated as nonhedge derivatives. From time to time, the company also enters into basis swaps to help mitigate its exposure to localized natural gas indices by, in effect, converting that exposure to NYMEX-based pricing. To the extent such basis swaps are coupled with NYMEX natural gas fixed-price swaps, they are accounted for as hedges; otherwise, any mark-to-market gains or losses are recognized currently in earnings.

At December 31, 2004, the following commodity-related derivatives were outstanding and represent those contracts that have not been designated as hedges or that do not qualify for hedge accounting treatment in the case of the costless and three-way collars acquired in the Westport merger.

Contract Type [(1)]	Period	Average Daily Volume	Average Contract Price
Natural Gas (Nonhedge)		**MMBtu**	**$/MMBtu**
Costless collars (NYMEX)	2005	60,000	$4.09 - $5.57
Three-way collars (NYMEX) [(5)]	2006	20,000	$4.00 - $6.00
Three-way average floor			$3.04
Basis swaps (CIG) [(2)]	Q1 - 2005	175,000	$0.71
	2006	20,000	$0.39
	2007	20,000	$0.39
	2008	4,973	$0.39
Basis swaps (NWPRM) [(3)]	Q1 - 2005	70,000	$0.71
	2006	15,000	$0.20
	2007	15,000	$0.20
	2008	15,000	$0.20
Basis swaps (HSC) [(4)]	Q1 - 2005	6,556	$0.36
Crude Oil (Nonhedge)		**Barrel**	**$/Barrel**
Three-way collars (WTI)	2005	5,000	$25.00 - $28.23
Three-way average floor			$20.93
	2006	2,000	$25.00 - $28.65
			$20.88

(1) These contracts may be subject to margin calls above certain limits established with individual counterparty institutions.

(2) Colorado Interstate Gas pipeline.

(3) Northwest Pipeline Rocky Mountain index.

(4) Houston Ship Channel.

(5) These derivatives function similar to a costless collar with the exception that if the NYMEX or WTI price, as applicable, falls below the three-way floor, the company loses price protection. For example, the company only has $.96/MMBtu of price protection if the NYMEX price falls below $3.04/MMBtu in the case of its 2006 natural gas three-way collars ($4.00 - $3.04).

The following hedge and nonhedge derivative contracts were entered into from January 1, 2005 through February 28, 2005.

Contract Type [1]	Period	Average Daily Volume	Average Contract Price
Natural Gas Hedges		**MMBtu**	**$/MMBtu**
Fixed-priced swaps (NYMEX)	Q2, Q3 - 2005	75,000	$6.09
	Q4 - 2005	25,272	$6.09
Costless collars (NYMEX)	Q2, Q3 - 2005	120,000	$6.00 - $7.00
	Q4 - 2005	40,435	$6.00 - $7.00
Basis swaps (CIG) [2]	Q2, Q3 - 2005	35,000	$0.75
	Q4 - 2005	11,793	$0.75
Basis swaps (NWPRM) [3]	Q2, Q3 - 2005	52,500	$0.73
	Q4 - 2005	17,690	$0.73
Basis swaps (HSC) [4]	Q2, Q3 - 2005	70,000	$0.13
	Q4 - 2005	23,587	$0.13
Crude Oil Hedges		**Barrel**	**$/Barrel**
Fixed-price swaps (WTI)	Q1 - 2005	4,589	$43.78
	Q2, Q3, Q4 - 2005	7,000	$43.78
Costless collars (WTI)	Q1 - 2005	4,589	$40.00 - $48.46
	Q2, Q3, Q4 - 2005	7,000	$40.00 - $48.46
Costless collars (Brent)	Q1 - 2005	3,278	$38.00 - $49.24
	Q2, Q3, Q4 - 2005	5,000	$38.00 - $49.24
Natural Gas (Nonhedge)			
Basis swaps (CIG) [2]	Q2, Q3 - 2005	35,000	$0.75
	Q4 - 2005	11,793	$0.75
Basis swaps (HSC) [4]	Q1 - 2005	49,667	$0.36
	Q2, Q3 - 2005	30,000	$0.13
	Q4 - 2005	23,370	$0.24

(1) These contracts may be subject to margin calls above certain limits established with individual counterparty institutions.

(2) Colorado Interstate Gas pipeline index.

(3) Northwest Pipeline Rocky Mountain index.

(4) Houston Ship Channel.

The company's marketing subsidiary, Kerr-McGee Energy Services (KMES) purchases third-party natural gas for aggregation and sale with the company's own production in the Rocky Mountain area. Under some of its marketing arrangements, KMES receives fixed prices for the sale of natural gas. Existing contracts for the physical delivery of gas at fixed prices have not been designated as hedges and are marked-to-market through earnings in accordance with FAS No. 133. KMES has entered into natural gas swaps and basis swaps that largely offset its fixed-price risk on physical contracts and lock in margins associated with the physical sales. The gains and losses on the swaps, which also are marked-to-market through earnings, substantially offset the gains and losses from the fixed-price physical delivery contracts.

Foreign Currency Exchange Rate Risk

The U.S. dollar is the functional currency for the company's international operations, except for its European chemical operations, for which the euro is the functional currency. Periodically, the company enters into forward contracts to buy and sell foreign currencies. Certain of these contracts (purchases of Australian dollars and British pound sterling, and sales of euro) have been designated and have qualified as cash flow hedges of the company's anticipated future cash flows related to pigment sales, capital expenditures, raw material purchases and operating costs. These contracts generally have durations of less than three years. Changes in the fair value of these contracts are recorded in accumulated other comprehensive income (loss) and are recognized in earnings in the periods during which the hedged forecasted transactions affect earnings.

As discussed above, under *Off-Balance Sheet Arrangements*, the company sells selected receivables in an accounts receivable monetization program for its pigment business. Receivables, including those denominated in foreign currency, are sold at their equivalent U.S. dollar value at the date of monetization. The company is collection agent and retains the risk of foreign currency rate changes between the date of sale and collection of the receivables. Under the terms of the accounts receivable monetization agreement, the company is required to enter into forward contracts for the value of the euro-denominated receivables sold into the program to mitigate its foreign currency risk. These contracts to sell foreign currency are considered nonhedge derivatives. Therefore, gains or losses on such contracts are recognized as a component of other income (expense) as incurred.

The company has entered into other forward contracts to sell foreign currencies, which will be collected as a result of pigment sales denominated in foreign currencies, primarily in European currencies. These contracts have not been designated as hedges even though they do protect the company from changes in foreign currency rates. Accordingly, gains or losses on such contracts are recognized in earnings as incurred.

The following table presents the notional amounts at the contract exchange rates and the weighted-average contractual exchange rates for contracts to purchase (sell) foreign currencies outstanding at year-end 2004 and 2003. All amounts are U.S. dollar equivalents. The estimated fair value of our foreign currency forward contracts is based on the year-end forward exchange rates quoted by financial institutions. At December 31, 2004 and 2003, the fair value of our foreign currency forward contracts was a net asset of $14 million and $17 million, respectively.

(Millions of dollars, except average contract rates)	Notional Amount	Weighted-Average Contract Rate
Open contracts at December 31, 2004 –		
Maturing in 2005 –		
British pound sterling	$ 186	$1.7104
Euro	151	1.3170
Euro	(292)	1.2977
British pound sterling	(1)	1.8043
Japanese yen	(1)	.0095
New Zealand dollar	(1)	.6873
Open contracts at December 31, 2003 –		
Maturing in 2004 –		
British pound sterling	$ 139	$1.6372
Australian dollar	38	.5366
Euro	(113)	1.1358
British pound sterling	(1)	1.6876
Japanese yen	(2)	.0092
New Zealand dollar	(1)	.6121
Maturing in 2005 –		
British pound sterling	$ 77	$1.5995

Interest Rate Risk

The company's exposure to changes in interest rates relates primarily to long-term debt obligations. The table below presents principal amounts and related weighted-average interest rates by maturity date for the company's long-term debt obligations outstanding at year-end 2004. All borrowings are in U.S. dollars.

(Millions of dollars)	2005	2006	2007	2008	2009	There-after	Total (2)	Fair Value 12/31/04
Fixed-rate debt –								
Principal amount	$ 1	$ –	$ –	$ –	$ –	$2,825	$2,826	$3,082
Weighted-average interest rate	9.61%	–	–	–	–	6.75%	6.75%	
Variable-rate debt (1) –								
Principal amount	$459	$307	$150	$ –	$ 41	$ –	$ 957	$ 957
Weighted-average interest rate	4.16%	5.30%	5.55%	–	2.70%	–	4.68%	

(1) *Includes fixed-rate debt with interest rate swaps to variable rate.*

(2) Principal amounts represent future payments and exclude the unamortized discount on issuance of $85 million and the net fair value hedge adjustments of $(1) million.

Interest Rate Derivatives – In connection with the issuance of $350 million of 5.375% notes due April 15, 2005, the company entered into an interest rate swap arrangement in April 2002. The terms of the agreement effectively change the interest the company will pay on the debt until maturity from the fixed rate to a variable rate of LIBOR plus .875%. During February 2004, the company reviewed the composition of its outstanding debt and entered into additional interest rate swaps, converting an aggregate of $566 million in fixed-rate debt to variable-rate debt. Under the interest rate swaps, $150 million of 6.625% notes due October 15, 2007, were converted to pay a variable rate of LIBOR plus 3.35%; $109 million of 8.125% notes due October 15, 2005, were converted to pay a variable rate of LIBOR plus 5.86%; and $307 million of 5.875% notes due September 15, 2006, were converted to pay a variable rate of LIBOR plus 3.1%. The company considers these swaps to be hedges against the change in fair value of the related debt as a result of interest rate changes. The swaps are carried in the Consolidated Balance Sheet at their estimated fair value. Any unrealized gain or loss on the swaps is offset by a comparable gain or loss resulting from recording changes in the fair value of the related debt. Gains and losses on interest rate swaps, along with the changes in the fair value of the related debt, are reflected in interest and debt expense in the Consolidated Statement of Operations. The critical terms of the swaps match the terms of the debt; therefore, the swaps are considered highly effective and no hedge ineffectiveness has been recognized. At December 31, 2004 and 2003, the fair value of our interest rate swaps was a net asset of $1 million and $15 million, respectively.

Critical Accounting Policies

Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates, judgments and assumptions regarding matters that are inherently uncertain and that ultimately affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. Even so, the accounting principles used by the company generally do not impact the company's reported cash flows or liquidity. Generally, accounting rules do not involve a selection among alternatives, but involve a selection of the appropriate policies for applying the basic principles. Interpretation of the existing rules must be done and judgments made on how the specifics of a given rule apply to the company.

The more significant reporting areas impacted by management's judgments and estimates are exploratory drilling costs, crude oil and natural gas proved reserve estimation, recoverability of long-lived assets, accounting for business combinations, accounting for derivative instruments, environmental remediation, tax accruals and benefit plans. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, legal counsel, actuaries, environmental studies and historical experience in similar matters. Actual results could differ materially from those estimates as additional information becomes known.

Exploratory Drilling Costs

The company follows the successful efforts method of accounting for its oil and gas exploration and development activities. Exploration expenses, including geological and geophysical costs and exploratory dry holes, are charged against earnings. Costs of successful exploratory wells and related production equipment are capitalized and amortized using the unit-of-production method on a field-by-field basis as oil and gas is produced. The successful efforts method reflects the inherent unpredictability of exploring for oil and gas. This accounting method may yield significantly different operating results than the full-cost method.

Under the successful efforts method, the cost of drilling an exploratory well is capitalized pending determination of whether proved reserves can be attributed to the discovery. In the case of onshore wells and offshore wells in relatively shallow water, that determination usually can be made upon or shortly after cessation of exploratory drilling operations. However, such determination may take longer in other areas (particularly deepwater exploration and international locations) depending upon, among other things, the amount of hydrocarbons discovered, the outcome of planned geological and engineering studies, the need for additional future appraisal drilling to determine whether the discovery is sufficient to support an economic development plan, and the requirement for government sanctioning in certain international locations. As a consequence, the company has capitalized costs associated with exploratory wells on its Consolidated Balance Sheet at any point in time that may be charged to earnings in a future period if management determines that commercial quantities of hydrocarbons have not been discovered. At December 31, 2004, the company had capitalized exploratory drilling costs of approximately $136 million associated with ongoing exploration and/or appraisal activities, primarily in the deepwater Gulf of Mexico, Brazil, Alaska and China. Additional information regarding the amount of capitalized exploratory drilling costs and changes during the last three years is presented in Note 31 to the Consolidated Financial Statements included in Item 8 of this annual report on Form 10-K.

Proved Oil and Gas Reserves

The company's estimates of proved of oil and gas reserves are prepared by the company's engineers using available geological and reservoir data, as well as production performance data. The U.S. Securities and Exchange Commission has defined proved reserves as the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with "reasonable certainty" to be recoverable in future years from known reservoirs under existing economic and operating conditions. Even though the company's engineers are knowledgeable and follow authoritative guidelines for estimating proved reserves, they must make a number of subjective determinations based on professional judgments in developing the company's reserve estimates. Such estimates are reviewed annually and revised, either upward or downward, as warranted by additional data. Revisions of previous estimates can occur due to, among other things, changes in reservoir performance, commodity prices, economic conditions and governmental regulations. The company mitigates the inherent risks associated with reserve estimation through a comprehensive reserves administration process. See Note 32, "Crude Oil, Condensate, Natural Gas Liquids and Natural Gas Net Reserves (Unaudited)" to the Consolidated Financial Statements included in Item 8 of this annual report on Form 10-K for additional information concerning the reserve administration process and revisions to reserve estimates in each of the last three years, including the use of independent third-party engineers.

Oil and gas reserve estimates impact our financial statements in two important ways. First, proved reserves are used to calculate depreciation and depletion rates for capitalized costs associated with our proved oil and gas properties (i.e., depreciation and depletion expense is based on the percentage of proved reserves depleted in the current year). If previously estimated reserves for a particular oil and gas field are revised downward, depreciation and depletion expense will increase in the future. Conversely, increased reserve estimates will cause depreciation and depletion rates to decline. Second, proved reserves are used as a component of the basis for calculating expected future cash flows for impairment test purposes under FAS No. 144 whenever events or changes in circumstances indicate that an impairment loss may have occurred. We monitor our oil and gas properties for impairment based on current period operating results and reserve revisions which may indicate that the carrying amount of a particular oil and gas field is not recoverable. All else being equal, downward revisions of previous reserve estimates increase the likelihood that an impairment loss may be recognized. The periodic impairment losses shown in the company's Consolidated Financial Statements, in general terms, result from either downward reserve revisions due to changes in reservoir performance or fields that ceased production sooner than anticipated. Factors contributing to impairment losses on oil and gas properties recognized during each of the last three years are discussed above under *Results of Operation by Segment – Exploration and Production.*

Impairment of Assets

A long-lived asset is evaluated for potential impairment whenever events or changes in circumstances indicate that its carrying amount may be greater than its future net cash flows. Such evaluations involve a significant amount of judgment since the results are based on estimated future events, such as sales prices for oil, gas or chemicals; costs to produce these products; estimates of future oil and gas production; development costs and the timing thereof; the economic and regulatory climates; and other factors. The need to test an asset for impairment may result from significant declines in sales prices, downward revisions to previous oil and gas reserve estimates, increases in operating costs, and changes in environmental or abandonment regulations. Assets held for sale are reviewed for potential loss on sale when the company commits to a plan to sell and thereafter while the asset is held for sale. Losses are measured as the difference between fair value less costs to sell and the asset's carrying value. Estimates of anticipated sales prices are judgmental and subject to revision in future periods, although initial estimates usually are based on sales prices for similar assets and other valuation data. The company cannot predict when or if future impairment charges will be required for held-for-use assets or intangibles, or whether losses associated with held-for-sale properties will be recognized.

Business Combinations

Purchase Price Allocation - In connection with a business combination, the company is required to assign the cost of the acquisition to assets acquired and liabilities assumed and record deferred taxes for any differences between the assigned values and tax bases of assets and liabilities. Any excess of purchase price over the amounts assigned to assets and liabilities is recorded as goodwill. Most assets and liabilities are recorded in the opening balance sheet at their estimated fair values. The company uses all available information to make these fair value determinations, including information commonly considered by the company's engineers in valuing individual oil and gas properties and sales prices for similar assets. Estimated deferred taxes are based on available information concerning the tax basis of the acquired company's assets and liabilities and loss carryforwards at the merger date, although such estimates may change in the future as additional information becomes known. Any change in deferred tax assets and liabilities as of the merger date based on information that becomes available later is recorded as an increase or decrease in goodwill. The amount of goodwill recorded in any particular business combination can vary significantly depending upon the values attributed to assets acquired and liabilities assumed.

Goodwill - In connection with our acquisition of HS Resources in 2001 and our merger with Westport in 2004, we recorded a total of $1.2 billion of goodwill for the excess of the purchase price over the value assigned to individual assets acquired and liabilities assumed. The company is required to assess goodwill for impairment annually, or more often as circumstances warrant. The first step of that process is to compare the fair value of the reporting unit to which goodwill has been assigned to the carrying amount of the associated net assets and goodwill. If the estimated fair value is greater than the carrying amount of the reporting unit, then no impairment loss is required. The company completed its annual impairment test associated with the goodwill recognized in the HS Resources merger as of June 30, 2004 and no impairment was indicated. The goodwill associated with the Westport merger will not be tested for impairment until 2005. Although the company cannot predict when or if goodwill will be impaired in the future, impairment charges may occur if the company is unable to replace the value of its depleting asset base or if other adverse events (for example, lower sustained oil and gas prices) reduce the fair value of the associated reporting unit.

Derivative Instruments

The company is exposed to risk from fluctuations in crude oil and natural gas prices, foreign currency exchange rates, and interest rates. To reduce the impact of these risks on earnings and increase the predictability of its cash flows, from time to time the company enters into certain derivative contracts, primarily swaps and collars for a portion of its oil and gas production, forward contracts to buy and sell foreign currencies, and interest rate swaps. The company accounts for all its derivative instruments, in accordance with FAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." The commodity, foreign currency and interest rate contracts are measured at fair value and recorded as assets or liabilities in the Consolidated Balance Sheet. We have elected, under the provisions of FAS No. 133, to apply hedge accounting to the vast majority of our oil and gas commodity derivatives which has the effect of deferring unrealized gains and losses on these instruments in equity, as a component of accumulated other comprehensive income (loss), until such time as the hedged production is sold. Alternatively, we could have elected to recognize the unrealized gains and losses in current-period earnings, which would have resulted in significant earnings volatility in periods preceding the actual physical sale of oil and gas. If we had elected to apply this alternative treatment, an additional after-tax unrealized loss of $174 million would have been recognized in earnings prior to December 31, 2004. Our chosen accounting method has no bearing on the company's liquidity or our total debt to total capitalization ratio because, in either case, stockholder's equity is reduced by the unrealized loss.

Environmental Remediation and Other Contingency Reserves

Kerr-McGee management makes judgments and estimates in accordance with applicable accounting rules when it establishes reserves for environmental remediation, litigation and other contingent matters. Provisions for such matters are charged to expense when it is probable that a liability has been incurred and reasonable estimates of the liability can be made. Estimates of environmental liabilities, which include the cost of investigation and remediation, are based on a variety of matters, including, but not limited to, the stage of investigation, the stage of the remedial design, evaluation of existing remediation technologies, and presently enacted laws and regulations. In future periods, a number of factors could significantly change the company's estimate of environmental remediation costs, such as changes in laws and regulations, revisions to the remedial design, unanticipated construction problems, identification of additional areas or volumes of contamination, and changes in costs of labor, equipment and technology. Consequently, it is not possible for management to reliably estimate the amount and timing of all future expenditures related to environmental or other contingent matters and actual costs may vary significantly from the company's estimates. Before considering reimbursements of the company's environmental costs discussed below, the company provided $106 million, $94 million and $202 million for environmental remediation and restoration costs in 2004, 2003 and 2002, respectively, including provisions related to the company's forest products business reflected as a component of income (loss) from discontinued operations.

To the extent costs of investigation and remediation are recoverable from the U.S. government under Title X and under certain insurance policies and such recoveries are deemed probable, the company records a receivable. In considering the probability of receipt, the company evaluates its historical experience with receipts, as well as its claim submission experience. At December 31, 2004, estimated recoveries of environmental costs recorded in the Consolidated Balance Sheet totaled $94 million, of which $49 million was received in early 2005. Provisions for environmental remediation and restoration in the Consolidated Statement of Operations were reduced by $14 million, $32 million and nil in 2004, 2003 and 2002, respectively, for estimated recoveries.

For additional information about contingencies, refer to the *Environmental Matters* section that follows and Note 19 to the Consolidated Financial Statements in Item 8 of this annual report on Form 10-K.

Tax Accruals

The company has operations in several countries around the world and is subject to income and other similar taxes in these countries. The estimation of the amounts of income tax to be recorded by the company involves interpretation of complex tax laws and regulations, evaluation of tax audit findings, and assessment of how the foreign taxes affect domestic taxes. Although the company's management believes its tax accruals are adequate, differences may occur in the future, depending on the resolution of pending and new tax matters.

Benefit Plans

The company provides defined benefit retirement plans and certain nonqualified benefits for employees in the U.S., U.K., Germany and the Netherlands and accounts for these plans in accordance with FAS No. 87, "Employers' Accounting for Pensions." The various assumptions used and the attribution of the costs to periods of employee service are fundamental to the measurement of net periodic cost and pension obligations associated with the retirement plans. The company also provides certain postretirement health care and life insurance benefits and accounts for the related plans in accordance with FAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions." The postretirement benefit cost and obligation are also dependent on the company's assumptions used in the actuarially determined amounts.

The following are considered significant assumptions related to the company's U.S. and foreign retirement plans and the U.S. postretirement plan:

- Long-term rate of return (applies to funded plans only)
- Discount rate
- Rate of compensation increases
- Health care cost trend rate (applies to postretirement plan only)

Other factors considered in developing actuarial valuations include inflation rates, retirement rates, mortality rates and other factors. Assumed inflation rates are based on an evaluation of external market indicators. Retirement rates are based primarily on actual plan experience. The discussion that follows provides additional information about the assumptions made and their effect on the financial statements. Advice of independent actuaries is taken into account when forming assumptions.

U.S. Benefit Plans

Long-term rate of return - In forming the assumption of the U.S. long-term rate of return, the company takes into account the expected earnings on funds already invested, earnings on contributions expected to be received in the current year, and earnings on reinvested returns. The long-term rate of return estimation methodology for U.S. plans is based on a capital asset pricing model using historical data. The modeling is performed and updated semi-annually by a third-party consultant and incorporates current portfolio allocation, historical asset-class returns and an assessment of expected future performance using asset-class risk factors. Based on this information, the company selected a long-term rate of return assumption of 8.5% as of year-end 2003 and 8.25% as of year-end 2004 for the U.S. pension plans.

When calculating expected return on plan assets for U.S. pension plans, the company uses a market-related value of assets that spreads asset gains and losses (differences between actual return and expected return) over five years. As of January 1, 2005, the amount of unrecognized losses on U.S. pension assets was $90 million. As these losses are recognized during future years in the market-related value of assets, they will result in cumulative increases in net periodic pension cost of $7 million in 2006 through 2009.

A 25 basis point increase/decrease in the company's expected long-term rate of return assumption as of the beginning of 2005 would decrease/increase net periodic pension cost for U.S. pension plans for 2005 by $3 million. The change would not affect expected contributions to fund the company's U.S. pension plans.

The net effect of the U.S. pension plans on 2004 results of operations was expense of $1 million. This consisted of $14 million expense attributable to a curtailment loss and special termination benefits and $13 million reduction of expense due to the expected return on assets exceeding other components of 2004 net periodic pension cost. The total expected return on assets of the U.S. pension plans for 2004 was $110 million, compared with an actual return of $100 million. During 2004, the company's contributions to the retirement plans totaled $39 million for certain U.S. nonqualified plans.

Discount rate - The company selects a discount rate assumption as of December 31 each year based on the average current yields on high quality long-term fixed income instruments. For U.S. plans, the average Moody's Long-Term AA Corporate Bond Yield and the Citigroup Pension Liability Index are used as a guide in the selection of the discount rate. The discount rates selected for year-end 2003 and 2004 were 6.25% and 5.75%, respectively. The decrease in the discount rate effective December 31, 2004 is expected to increase 2005 net periodic pension cost by approximately $2 million, but is not expected to affect future contributions made to the plans.

Rate of compensation increases - The company determines this assumption based on its long-term plans for compensation increases specific to employee groups covered and expected economic conditions. The assumed rate of salary increases includes the effects of merit increases, promotions and general inflation. The rate of 4.5% was selected for both year-end 2003 and 2004.

Health care cost trend rate - The health care cost trend assumptions are developed based on historical cost data, the near-term outlook and an assessment of likely long-term trends. The company chooses an initial medical trend rate and an ultimate medical trend rate, as well as the number of years it will take to move between the two rates. The initial and the ultimate medical trend rates chosen for both 2003 and 2004 year-ends were 10% and 5%. In both cases, the number of years that it will take to move to the ultimate trend rate was six. A 1% increase in the assumed health care cost trend rate for each future year would increase the year-end 2004 postretirement benefit obligation by $14 million and increase the aggregate of the service and interest cost components of the 2004 net periodic postretirement expense by $1 million.

Foreign Benefit Plans

Long-term rate of return - Our assumption of the long-term rate of return for the U.K. and the Netherlands plans is based on the advice of the third-party consultants, considering portfolio mix and the rates of return on local government and corporate bonds. The long-term rates of return chosen as of year-end 2003 and 2004 were 7.25% and 7.0%, respectively, for the U.K. plan. For the Netherlands plan, the long-term rate of return assumption was 5.75% at year-end 2003 and 5.5% at year-end 2004.

Discount rate - For foreign plans, the company bases the estimates on local corporate bond index rates. The discount rates selected for the foreign plans at December 31, 2003 ranged from 5.25% to 5.5%. The respective rates for year-end 2004 ranged from 4.75% to 5.25%.

Rate of compensation increases - Consistent with the U.S. plans, the company determines this assumption based on its long-term plans for compensation increases specific to employee groups covered. The assumed rate of salary increases includes the effects of merit increases, promotions and general inflation. The rates of compensation increases for the foreign retirement plans ranged from 2.75% - 5.0% at year-end 2003 and from 3.0% - 4.75% at year-end 2004.

The above description of the company's critical accounting policies is not intended to be an all-inclusive discussion of the uncertainties considered and estimates made by management in applying accounting principles and policies. Results may vary significantly if different policies were used or required and if new or different information becomes known to management.

Environmental Matters

The company's affiliates are subject to various environmental laws and regulations in the United States and in the foreign countries in which they operate. Under these laws, the company's affiliates are or may be required to obtain or maintain permits and/or licenses in connection with their operations. In addition, under these laws, the company's affiliates are or may be required to remove or mitigate the effects on the environment of the disposal or release of certain chemical, petroleum, low-level radioactive and other substances at various sites. Environmental laws and regulations are becoming increasingly stringent, and compliance costs are significant and will continue to be significant in the foreseeable future. There can be no assurance that such laws and regulations or any environmental law or regulation enacted in the future will not have a material effect on the company's operations or financial condition.

Sites at which the company's affiliates have environmental responsibilities include sites that have been designated as Superfund sites by the U.S. Environmental Protection Agency (EPA) pursuant to the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA), as amended, and that are included on the National Priority List (NPL). As of December 31, 2004, the company's affiliates had received notices that they had been named potentially responsible parties (PRP) with respect to 13 existing EPA Superfund sites on the NPL that require remediation. The company does not consider the number of sites for which its affiliates have been named a PRP to be the determining factor when considering the company's overall environmental liability. Decommissioning and remediation obligations, and the attendant costs, vary substantially from site to site and depend on unique site characteristics, available technology and the regulatory requirements applicable to each site. Additionally, the company's affiliates may share liability at some sites with numerous other PRPs, and the law currently imposes joint and several liability on all PRPs under CERCLA. The company's affiliates are also obligated to perform or have performed remediation or remedial investigations and feasibility studies at sites that have not been designated as Superfund sites by EPA. Such work is frequently undertaken pursuant to consent orders or other agreements.

Current Businesses

The company's oil and gas affiliates are subject to numerous international, federal, state and local laws and regulations relating to environmental protection. In the United States, these include the Federal Water Pollution Control Act, commonly known as the Clean Water Act, the Clean Air Act and the Resource Conservation and Recovery Act (RCRA). These laws and regulations govern, among other things, the amounts and types of substances and materials that may be released into the environment; the issuance of permits in connection with exploration, drilling and production activities; the release of emissions into the atmosphere; and the discharge and disposition of waste materials. Environmental laws and regulations also govern offshore oil and gas operations, the implementation of spill prevention plans, the reclamation and abandonment of wells and facility sites, and the remediation and monitoring of contaminated sites. The company's chemical affiliates are subject to a broad array of international, federal, state and local laws and regulations relating to environmental protection, including the Clean Water Act, the Clean Air Act, CERCLA and RCRA. These laws require the company's affiliates to undertake various activities to reduce air emissions, eliminate the generation of hazardous waste, decrease the volume of wastewater discharges and increase the efficiency of energy use.

Discontinued Businesses

The company's affiliates historically have held interests in various businesses in which they are no longer engaged or which they intend to exit. Such businesses include the refining and marketing of oil and gas and associated petroleum products, the mining and processing of uranium and thorium, the production of ammonium perchlorate, the treatment of forest products and other activities. Although the company's affiliates are no longer engaged in certain businesses, residual obligations may still exist, including obligations related to compliance with environmental laws and regulations, including the Clean Water Act, the Clean Air Act, CERCLA and RCRA. These laws and regulations require company affiliates to undertake remedial measures at sites of current or former operations or at sites where waste was disposed. For example, company affiliates are required to conduct decommissioning and environmental remediation at certain refineries, distribution facilities and service stations they owned and/or operated before exiting the refining and marketing business in 1995. Company affiliates also are required to conduct decommissioning and remediation activities at sites where they were involved in the exploration, production, processing and/or sale of uranium or thorium and at sites where they were involved in the production and sale of ammonium perchlorate. Additionally, the company's chemical affiliate is decommissioning and remediating its wood-treatment facilities as part of its exit from the forest products business.

Environmental Costs

Expenditures for environmental protection and cleanup for each of the last three years and for the three-year period ended December 31, 2004, are as follows:

(Millions of dollars)	**2004**	2003	2002	Total
Charges to environmental reserves	**$ 99**	$104	$128	$331
Recurring expenses	**17**	19	37	73
Capital expenditures	**15**	18	22	55
Total	**$131**	$141	$187	$459

In addition to past expenditures, reserves have been established for the remediation and restoration of active and inactive sites where it is probable that future costs will be incurred and the liability is reasonably estimable. For environmental sites, the company considers a variety of matters when setting reserves, including the stage of investigation; whether EPA or another relevant agency has ordered action or quantified cost; whether the company has received an order to conduct work; whether the company participates as a PRP in the Remedial Investigation/Feasibility Study (RI/FS) process and, if so, how far the

RI/FS has progressed; the status of the record of decision by the relevant agency; the status of site characterization; the stage of the remedial design; evaluation of existing remediation technologies; the number and financial condition of other potential PRPs; and whether the company reasonably can evaluate costs based upon a remedial design and/or engineering plan.

After the remediation work has begun, additional accruals or adjustments to costs may be made based on any number of developments, including revisions to the remedial design; unanticipated construction problems; identification of additional areas or volumes of contamination; inability to implement a planned engineering design or to use planned technologies and excavation methods; changes in costs of labor, equipment and/or technology; any additional or updated engineering and other studies; and weather conditions.

As of December 31, 2004, the company's financial reserves for all active and inactive sites totaled $255 million. This includes $106 million added in 2004 for active and inactive sites. In the Consolidated Balance Sheet, $158 million of the total reserve is classified as noncurrent liabilities-other, and the remaining $97 million is included in accrued liabilities. Management believes that currently the company has reserved adequately for the reasonably estimable costs of known environmental contingencies. However, additional reserves may be required in the future due to the previously noted uncertainties. Additionally, there may be other sites where the company has potential liability for environmental-related matters but for which the company does not have sufficient information to determine that the liability is probable and/or reasonably estimable. The company has not established reserves for such sites.

The following table reflects the company's portion of the known estimated costs of investigation and/or remediation that are probable and estimable. The table summarizes EPA Superfund NPL sites where the company and/or its affiliates have been notified it is a PRP under CERCLA and other sites for which the company had financial reserves recorded at year-end 2004. In the table, aggregated information is presented for certain sites that are individually not significant (each has a remaining reserve balance of less than $10 million). Amounts reported in the table for the West Chicago sites are not reduced for actual or expected reimbursement from the U.S. government under Title X of the Energy Policy Act of 1992 (Title X), described in Note 19 to the Consolidated Financial Statements included in Item 8 of this annual report on Form 10-K.

Location of Site	Stage of Investigation/Remediation	Total Expenditures Through 2004	Remaining Reserve Balance at December 31, 2004	Total
		(Millions of dollars)		
EPA Superfund sites on National Priority List (NPL)				
West Chicago, Ill. Vicinity areas	Remediation of thorium tailings at Residential Areas and Reed-Keppler Park is substantially complete. An agreement in principle for cleanup of thorium tailings at Kress Creek and Sewage Treatment Plant has been reached with relevant agencies; court approval expected in 2005.	$ 118	$ 86	$ 204
Milwaukee, Wis.	Completed soil cleanup at former wood-treatment facility and began cleanup of offsite tributary creek. Groundwater remediation and cleanup of tributary creek is continuing.	39	6	45
Other sites	Sites where the company has been named a PRP, including landfills, wood-treating sites, a mine site and an oil recycling refinery. These sites are in various stages of investigation/remediation.	32	16	48
		189	108	297
Sites under consent order, license or agreement, not on EPA Superfund NPL				
West Chicago, Ill. Former manufacturing facility	Excavation, removal and disposal of contaminated soils at former thorium mill is substantially complete. The site will be used for moving material from the Kress Creek and Sewage Treatment Plan remediation sites. Surface restoration and groundwater monitoring and remediation will continue.	444	14	458
Los Angeles County, Cal.	Excavation, removal and disposal of soils contaminated with wastes from oil and gas production is ongoing.	14	25	39
Cushing, Okla.	Excavation, removal and disposal of thorium and uranium residuals was substantially completed in 2004. Investigation of and remediation addressing hydrocarbon contamination is continuing.	141	21	162
Henderson, Nev.	Groundwater treatment to address perchlorate contamination is being conducted under consent decree with Nevada Department of Environmental Protection.	119	10	129
Other sites	Sites related to wood-treatment, chemical production, landfills, mining, oil and gas production, and petroleum refining, distribution and marketing. These sites are in various stages of investigation/remediation.	311	77	388
		1,029	147	1,176
	Total	$1,218	$255	$1,473

The company has not recorded in the financial statements potential reimbursements from governmental agencies or other third parties, except for amounts due from the U.S. government under Title X for costs incurred by the company on its behalf and recoveries under certain insurance policies. If recoveries from third parties, other than recovery from the U.S. government under Title X and recoveries under certain insurance policies become probable, they will be disclosed but will not generally be recorded in the financial statements until received.

Sites specifically identified in the table above are discussed in Note 19 to the Consolidated Financial Statements which financial statements are included in Item 8 of this annual report on Form 10-K. Discussion in Note 19 of the West Chicago, Illinois; Henderson, Nevada; Los Angeles County, California; Milwaukee, Wisconsin; and Cushing, Oklahoma sites is incorporated herein by reference and made fully a part hereof.

New/Revised Accounting Standards

The Financial Accounting Standards Board (FASB) has proposed an amendment to Statement No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies" (FAS No. 19) that may change the way oil and gas producers account for deferred exploratory drilling costs. Under the current rules, there is a presumption that all exploratory drilling costs will be expensed within one year following completion of drilling if proved reserves have not been recorded, except for costs related to areas where additional exploration wells are necessary to justify development plans *and* such additional wells are under way or firmly planned for the near future. Application of FAS No. 19 to the facts and circumstances commonly faced by oil and gas producers in today's exploration and development environment (particularly in deepwater and international areas) has become a concern for the industry and there are diverse views in practice. For example, in the case of deepwater discoveries, additional appraisal wells are almost never under way or firmly planned when the drilling rig is released due to the time required to assess the initial discovery well, update geologic models, and plan appraisal well locations in an extremely high-cost drilling environment.

The new standard would relax the one-year limitation, so long as oil and gas reserves have been discovered and an enterprise "is making sufficient progress assessing the reserves and the economic and operating viability of the project." The FASB staff has developed indicators to help determine whether sufficient progress is being made. The company believes the adoption of the proposed amendment (once finalized) will have no impact on its consolidated financial statements. Additional information related to exploratory drilling costs is included in Note 31 to the Consolidated Financial Statements included in Item 8 of this annual report on Form 10-K.

In December 2004, the FASB issued FASB Staff Position No. FAS 109-2 (FSP No. 109-2), "Accounting and Disclosure Guidance for the Foreign Earnings Repatriation Provisions within the American Jobs Creation Act of 2004" (the Jobs Act). FSP No. 109-2 provides guidance with respect to reporting the potential impact of the repatriation provisions of the Jobs Act on an enterprise's income tax expense and deferred tax liability. The Jobs Act was enacted on October 22, 2004, and provides for a temporary 85% dividends received deduction on certain foreign earnings repatriated during a one-year period. The deduction would result in an approximate 5.25% federal tax rate on the repatriated earnings. To qualify for the deduction, the earnings must be reinvested in the United States pursuant to a domestic reinvestment plan established by a company's chief executive officer and approved by a company's board of directors. Certain other criteria in the Jobs Act must be satisfied as well. FSP No. 109-2 states that an enterprise is allowed time beyond the financial reporting period to evaluate the effect of the Jobs Act on its plan for reinvestment or repatriation of foreign earnings. The company has not yet completed its evaluation of the impact of the repatriation provisions of the Jobs Act. Accordingly, as provided for in FSP No. 109-2, the company has not adjusted its tax expense or deferred tax liability to reflect the repatriation provisions of the Jobs Act. Additional disclosures related to the status of our evaluation of the Jobs Act repatriation provisions are included in Note 15 to the Consolidated Financial Statements included in Item 8 of this annual report on Form 10-K.

In December 2004, the FASB issued FASB Staff Position 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," indicating that this deduction, which will be available to the company in 2005, should be accounted for as a special deduction in accordance with the provisions of FAS No. 109, as opposed to a tax-rate reduction. Beginning in 2005, the company will recognize the allowable deductions as qualifying activity occurs.

In December 2004, the FASB issued Statement No. 123 (revised 2004), "Share-Based Payment" (FAS No. 123R), which replaces FAS No. 123 and supersedes APB Opinion No. 25, "Accounting for Stock Issued to Employees." FAS No. 123R requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on their fair values beginning with the first interim period after June 15, 2005, with early adoption encouraged. The pro forma disclosures previously permitted under FAS No. 123 no longer will be an alternative to financial statement recognition. The company is required to adopt FAS No. 123R in the third quarter of 2005. Under FAS No. 123R, the company must determine the appropriate fair value model to be used for valuing share-based payments, the amortization method for compensation cost and the transition method to be used at date of adoption. The permitted transition methods include either retrospective or prospective adoption. Under the retrospective method of adoption, prior periods may be restated either as of the beginning of the year of adoption (modified retrospective method) or for all periods presented. The prospective method requires that compensation expense be recorded for all unvested share-based compensation awards at the beginning of the first quarter of adoption of FAS No. 123R, while the retrospective methods would record compensation expense for all unvested share-based compensation awards beginning with the first period presented. The company is currently evaluating the requirements of FAS No. 123R and expects to adopt this standard no later than July 1, 2005 using either the prospective or the modified retrospective method of adoption. The company expects that the effect of adoption will not have a material effect on our financial condition and cash flows, and that the effect on our results of operations will be comparable to the current pro forma disclosures under FAS No. 123 included in Note 1 to the Consolidated Financial Statements.

Item 7a. Quantitative and Qualitative Disclosure about Market Risk

For information required under this section, see the *Market Risks* section of Management's Discussion and Analysis included in Item 7 of this annual report on Form 10-K.

Item 8. Financial Statements and Supplementary Data

Index to Supplementary Data

Index to the Financial Statement Schedules

All other schedules are omitted because they are either not required, not significant, not applicable or the information is presented in the financial statements or the notes to the financial statements.

Management's Report on Internal Control over Financial Reporting

The management of Kerr-McGee Corporation (the company) is responsible for establishing and maintaining adequate internal control over financial reporting. The company's internal control over financial reporting is a process designed under the supervision of the company's Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the company's financial statements for external purposes in accordance with accounting principles generally accepted in the U.S.

As of December 31, 2004, management assessed the effectiveness of the company's internal control over financial reporting based on the criteria for effective internal control over financial reporting established in "Internal Control - Integrated Framework," issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, management determined that the company maintained effective internal control over financial reporting as of December 31, 2004, based on those criteria.

Ernst & Young, LLP, the independent registered public accounting firm that audited the Consolidated Financial Statements of the company included in this annual report on Form 10-K, has issued an attestation report on management's assessment of the effectiveness of the company's internal control over financial reporting as of December 31, 2004. The report, which expresses unqualified opinions on management's assessment and on the effectiveness of the company's internal control over financial reporting as of December 31, 2004, is included under the heading "Report of Independent Registered Public Accounting Firm on Internal Control over Financial Reporting."

(Luke R. Corbett)
Luke R. Corbett, Director
Chief Executive Officer

(Robert M. Wohleber)
Robert M. Wohleber
Senior Vice President and
Chief Financial Officer

March 11, 2005

Report of Independent Registered Public Accounting Firm on Internal Control over Financial Reporting

The Board of Directors and Stockholders
Kerr-McGee Corporation

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that Kerr-McGee Corporation maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Kerr-McGee Corporation'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 an opinion on management's assessment and an opinion on the effectiveness of the company's internal control over financial reporting based on our audit.

We conducted our audit 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. Our audit included 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 considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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.

In our opinion, management's assessment that Kerr-McGee Corporation maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, Kerr-McGee Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2004 consolidated financial statements of Kerr-McGee Corporation and our report dated March 11, 2005, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Oklahoma City, Oklahoma
March 11, 2005

Report of Independent Registered Public Accounting Firm on Consolidated Financial Statements

The Board of Directors and Stockholders
Kerr-McGee Corporation

We have audited the accompanying consolidated balance sheets of Kerr-McGee Corporation as of December 31, 2004 and 2003, and the related consolidated statements of operations, comprehensive income (loss) and stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2004. Our audits also included the financial statement schedule listed in the Index in Item 8. These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Kerr-McGee Corporation at December 31, 2004 and 2003, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*. As discussed in Note 14 to the consolidated financial statements, effective December 31, 2003, the Company adopted FASB Interpretation No. 46, *Consolidation of Variable Interest Entities*.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Kerr-McGee Corporation's internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 11, 2005, expressed an unqualified opinion thereon.

/S/ ERNST & YOUNG LLP

Oklahoma City, Oklahoma
March 11, 2005

Consolidated Statement of Operations

(Millions of dollars, except per-share amounts)	**2004**	2003	2002
Revenues	**$5,157**	$4,080	$3,515
Costs and Expenses			
Costs and operating expenses	**1,953**	1,563	1,343
Selling, general and administrative expenses	**337**	365	308
Shipping and handling expenses	**166**	139	124
Depreciation and depletion	**1,060**	742	809
Accretion expense	**30**	25	–
Asset impairments	**36**	14	646
Loss (gain) associated with assets held for sale	**29**	(45)	176
Exploration, including exploratory dry holes and amortization of undeveloped leases	**356**	354	273
Taxes, other than income taxes	**148**	96	102
Provision for environmental remediation and restoration, net of reimbursements	**86**	60	53
Interest and debt expense	**245**	251	275
Total Costs and Expenses	**4,446**	3,564	4,109
	711	516	(594)
Other Income (Expense)	**(40)**	(57)	(31)
Income (Loss) from Continuing Operations before Income Taxes	**671**	459	(625)
Benefit (Provision) for Income Taxes	**(256)**	(195)	35
Income (Loss) from Continuing Operations	**415**	264	(590)
Income (Loss) from Discontinued Operations, including tax benefit of $6 in both 2004 and 2003, and $33 in 2002	**(11)**	(10)	105
Cumulative Effect of Change in Accounting Principle, including tax benefit of $18	**–**	(35)	–
Net Income (Loss)	**$ 404**	$ 219	$ (485)
Income (Loss) per Common Share			
Basic –			
Continuing operations	**$ 3.29**	$ 2.63	$(5.89)
Discontinued operations	**(.09)**	(.10)	1.05
Cumulative effect of change in accounting principle	**–**	(.35)	–
Net income (loss)	**$ 3.20**	$ 2.18	$(4.84)
Diluted –			
Continuing operations	**$ 3.19**	$ 2.58	$(5.89)
Discontinued operations	**(.08)**	(.09)	1.05
Cumulative effect of change in accounting principle	**–**	(.32)	–
Net income (loss)	**$ 3.11**	$ 2.17	$(4.84)

The accompanying notes are an integral part of this statement.

Consolidated Balance Sheet

(Millions of dollars)	2004	2003
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 76**	$ 142
Accounts receivable, net of allowance for doubtful accounts of $14 in 2004 and $10 in 2003	**963**	583
Inventories	**329**	394
Investment in equity securities	**–**	510
Derivatives and other assets	**195**	128
Deferred income taxes	**324**	76
Total Current Assets	**1,887**	1,833
Property, Plant and Equipment – Net	**10,827**	7,399
Investments, Derivatives and Other Assets	**165**	248
Deferred Charges	**343**	317
Intangible Assets	**91**	64
Long-Term Assets Associated with Properties Held for Disposal	**8**	32
Goodwill	**1,197**	357
Total Assets	**$14,518**	$10,250
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	**$ 644**	$ 475
Long-term debt due within one year	**463**	574
Income taxes payable	**201**	127
Derivative liabilities	**372**	354
Accrued liabilities	**825**	702
Total Current Liabilities	**2,505**	2,232
Long-Term Debt	**3,236**	3,081
Noncurrent Liabilities		
Deferred income taxes	**2,177**	1,335
Asset retirement obligations	**503**	385
Derivative liabilities	**208**	2
Other	**571**	563
Total Noncurrent Liabilities	**3,459**	2,285
Long-Term Liabilities Associated with Properties Held for Disposal	**–**	16
Stockholders' Equity		
Common stock, par value $1.00 – 300,000,000 shares authorized, 152,049,127 shares issued in 2004 and 100,892,354 shares issued in 2003	**152**	101
Capital in excess of par value	**4,205**	1,708
Preferred stock purchase rights	**2**	1
Retained earnings	**1,102**	927
Accumulated other comprehensive loss	**(79)**	(45)
Common stock in treasury, at cost – 159,856 shares in 2004 and 31,924 shares in 2003	**(8)**	(2)
Deferred compensation	**(56)**	(54)
Total Stockholders' Equity	**5,318**	2,636
Total Liabilities and Stockholders' Equity	**$14,518**	$10,250

The "successful efforts" method of accounting for oil and gas exploration and production activities has been followed in preparing this balance sheet.

The accompanying notes are an integral part of this statement.

Consolidated Statement of Cash Flows

(Millions of dollars)	**2004**	2003	2002
Cash Flows from Operating Activities			
Net income (loss)	**$ 404**	$ 219	$ (485)
Adjustments to reconcile net income (loss) to net cash provided by operating activities –			
Depreciation, depletion and amortization	**1,124**	814	884
Deferred income taxes	**108**	156	(112)
Dry hole expense	**161**	181	113
Asset impairments	**36**	14	652
(Gain) loss on assets held for sale and asset disposal	**20**	(40)	100
Accretion expense	**30**	25	–
Cumulative effect of change in accounting principle	**–**	35	–
Provision for environmental remediation and restoration, net of reimbursements	**92**	62	89
Other noncash items affecting net income (loss)	**160**	94	76
Changes in assets and liabilities, net of effects of operations acquired-			
(Increase) decrease in accounts receivable	**(236)**	45	(104)
Decrease in inventories	**83**	22	37
Decrease in deposits, prepaids and other assets	**48**	12	185
Increase (decrease) in accounts payable, derivatives and accrued liabilities	**136**	(57)	166
Increase in income taxes payable	**28**	66	49
Other	**(144)**	(130)	(202)
Net cash provided by operating activities	**2,050**	1,518	1,448
Cash Flows from Investing Activities			
Capital expenditures	**(1,262)**	(981)	(1,159)
Dry hole costs	**(78)**	(181)	(113)
Acquisitions, net of cash acquired (1)	**43**	(110)	(24)
Purchase of long-term investments	**(29)**	(39)	(65)
Proceeds from sale of long-term investments	**39**	50	12
Proceeds from sale of assets	**23**	304	756
Other investing activities	**2**	6	–
Net cash used in investing activities	**(1,262)**	(951)	(593)
Cash Flows from Financing Activities			
Issuance of long-term debt (1)	**677**	31	418
Issuance of common stock (1)	**55**	–	5
Repayment of debt	**(1,278)**	(369)	(1,101)
Dividends paid	**(205)**	(181)	(181)
Settlement of Westport derivatives	**(101)**	–	–
Other financing activities	**1**	(1)	–
Net cash used in financing activities	**(851)**	(520)	(859)
Effects of Exchange Rate Changes on Cash and Cash Equivalents	**(3)**	5	3
Net Increase (Decrease) in Cash and Cash Equivalents	**(66)**	52	(1)
Cash and Cash Equivalents at Beginning of Year	**142**	90	91
Cash and Cash Equivalents at End of Year	**$ 76**	$ 142	$ 90

(1) See Notes 2 and 4 for information regarding the business combination that occurred in 2004 and the related noncash financing and investing activities.

The accompanying notes are an integral part of this statement.

Consolidated Statement of Comprehensive Income (Loss) and Stockholders' Equity

Millions of dollars)	Common Stock	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock	Deferred Compensation and Other	Total Stockholders' Equity
Balance at December 31, 2001	$100	$1,676	$1,543	$(64)	$ –	$(81)	$3,174
Comprehensive Income (Loss):							
Net loss	–	–	(485)	–	–	–	(485)
Other comprehensive income	–	–	–	2	–	–	2
Comprehensive loss							(483)
Shares issued	–	5	–	–	–	–	5
Dividends declared ($1.80 per share)	–	–	(181)	–	–	–	(181)
Tax benefit from stock-based awards	–	1	–	–	–	–	1
Other	–	5	9	–	–	6	20
Balance at December 31, 2002	100	1,687	886	(62)	–	(75)	2,536
Comprehensive Income (Loss):							
Net income	–	–	219	–	–	–	219
Other comprehensive income	–	–	–	17	–	–	17
Comprehensive income							236
Shares issued	–	1	–	–	–	–	1
Restricted stock activity	1	21	–	–	(1)	(10)	11
ESOP deferred compensation	–	–	–	–	–	32	32
Dividends declared ($1.80 per share)	–	–	(182)	–	–	–	(182)
Other	–	(1)	4	–	(1)	–	2
Balance at December 31, 2003	101	1,708	927	(45)	(2)	(53)	2,636
Comprehensive Income (Loss):							
Net income	–	–	404	–	–	–	404
Other comprehensive loss	–	–	–	(34)	–	–	(34)
Comprehensive income							370
Westport merger	49	2,402	–	–	–	(3)	2,448
Shares issued	2	53	–	–	–	–	55
Restricted stock activity	–	24	–	–	(6)	(5)	13
ESOP deferred compensation	–	–	–	–	–	7	7
Dividends declared ($1.80 per share)	–	–	(228)	–	–	–	(228)
Tax benefit from stock-based awards	–	18	–	–	–	–	18
Other	–	–	(1)	–	–	–	(1)
Balance at December 31, 2004	$152	$4,205	$1,102	$(79)	$(8)	$(54)	$5,318

The accompanying notes are an integral part of this statement.

1. The Company and Significant Accounting Policies

Kerr-McGee is an energy and inorganic chemical company with worldwide operations. The exploration and production unit explores for, develops, produces and markets crude oil and natural gas, with major areas of operation in the United States, the United Kingdom sector of the North Sea and China. Exploration efforts also extend to Australia, Benin, Bahamas, Brazil, Morocco, Canada, and the Danish and Norwegian sectors of the North Sea. The chemical unit is primarily engaged in production and marketing of titanium dioxide pigment and has production facilities in the United States, Australia, Germany and the Netherlands.

Basis of Presentation

The consolidated financial statements include the accounts of all subsidiary companies that are more than 50% owned, the proportionate share of joint ventures in which the company has an undivided interest and variable interest entities for which the company is considered the primary beneficiary. Investments in affiliated companies that are 20% to 50% owned are carried as a component of investments, derivatives and other assets in the Consolidated Balance Sheet at cost adjusted for equity in undistributed earnings. Except for dividends and changes in ownership interest, changes in equity in undistributed earnings are included in the Consolidated Statement of Operations. All material intercompany transactions have been eliminated.

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates as additional information becomes known.

Discontinued operations in the consolidated financial statements represent the company's former forest products operations and oil and gas operations in Kazakhstan, Indonesia and Australia (see Note 25).

Reclassifications

Certain prior year amounts have been reclassified to conform with the current year presentation.

Foreign Currency Translation

The U.S. dollar is considered the functional currency for each of the company's international operations, except for its European chemical operations. Foreign currency transaction gains or losses are recognized in the period incurred and are included in other income (expense) in the Consolidated Statement of Operations. The company recorded net foreign currency transaction losses of $21 million, $41 million and $38 million in 2004, 2003 and 2002, respectively.

The euro is the functional currency for the European chemical operations. Translation adjustments resulting from translating the functional currency financial statements into U.S. dollar equivalents are reflected as a separate component of other comprehensive income (loss) in Note 3.

Cash Equivalents

The company considers all investments with maturity of three months or less to be cash equivalents. Cash equivalents totaling $17 million in 2004 and $72 million in 2003 were comprised of time deposits, certificates of deposit and U.S. government securities.

Accounts Receivable and Receivable Sales

Accounts receivable are reflected at their net realizable value, reduced by an allowance for doubtful accounts to allow for expected credit losses. The allowance is estimated by management, based on factors such as age of the related receivables and historical experience, giving consideration to customer profiles. The company does not generally charge interest on accounts receivable; however, certain operating agreements have provisions for interest and penalties that may be invoked if deemed necessary. Accounts receivable are aged in accordance with contract terms and are written off when deemed uncollectible. Any subsequent recoveries of amounts written off are credited to the allowance for doubtful accounts.

Under an accounts receivable monetization program, Kerr-McGee sells selected pigment customers' accounts receivable to a special-purpose entity (SPE). The company does not own any of the common stock of the SPE. When the receivables are sold, Kerr-McGee retains an interest in excess receivables that serve as over-collateralization for the program and retains interests for servicing and in preference stock of the SPE. The interest in the preference stock is essentially a deposit to provide further credit enhancement to the securitization program, if needed, but otherwise is recoverable by the company at the end of the program. Management believes the servicing fee represents adequate compensation and is equal to what would otherwise be charged by an outside servicing agent. The loss associated with the receivable sales is determined as the difference in the book value of receivables sold and the total of cash and fair value of the deposit retained by the SPE. The losses are recorded in other income (expense). The estimate of fair value of the retained interests is based on the present value of future cash flows discounted at rates estimated by management to be commensurate with the risks.

Concentration of Credit Risk

The company has significant credit risk exposure due to concentration of its crude oil and natural gas receivables with several significant customers. The two largest purchasers of oil and gas production accounted for 40% of total crude oil and natural gas sales revenues in 2004. To reduce credit risk, the company performs ongoing evaluations of its customers' financial condition, including establishing credit limits for its customers, and uses credit risk insurance policies from time to time as deemed appropriate to mitigate credit risk. The company does not generally require collateral.

Inventories

Inventories are stated at the lower of cost or market. The costs of the company's product inventories are determined by the first-in, first-out (FIFO) method. Inventory carrying values include material costs, labor and associated indirect manufacturing expenses. Costs for materials and supplies, excluding ore, are determined by average cost to acquire. Ore inventories are carried at actual cost.

Property, Plant and Equipment

Exploration and Production - Exploration expenditures, including geological and geophysical costs, delay rentals and exploration department overhead are charged against earnings as incurred. Costs of drilling exploratory wells are capitalized pending determination of whether proved reserves can be attributed to the discovery. If management determines that commercial quantities of hydrocarbons have not been discovered, capitalized costs associated with exploratory wells are charged to dry hole costs. Costs of successful exploratory wells, all developmental wells, production equipment and facilities are capitalized and then depleted using the unit-of-production method by field as oil and gas are produced. See Note 31 for additional information related to capitalized exploratory drilling costs.

Lease acquisition costs on unproved oil and gas properties are capitalized and amortized over their lease terms at rates that provide for full amortization upon abandonment. Costs of abandoned leases are charged to the accumulated amortization accounts, while costs of productive leases are transferred to proved oil and gas properties. Under this method, the costs of all unsuccessful leases are charged to exploration expense while the cost of successful activities become part of the carrying amount of proved properties and are depleted on a unit-of-production basis as described above. In the case of unproved property costs (probable and possible reserve value) associated with proved fields acquired in a business combination, recoverability is assessed on a field-by-field basis and a loss is recognized, if indicated, based on the results of drilling activity, planned future drilling activity and management's estimate of the remaining value attributed to the probable and possible reserves. Costs of fields not expected to be developed are charged to expense when that determination is made, while successful activities become part of the carrying amount of proved properties and are depleted on a unit-of-production basis as described above.

Other - Property, plant and equipment is stated at cost less reserves for depreciation, depletion and amortization. Maintenance and repairs are expensed as incurred, except that costs of replacements or renewals that improve or extend the lives of existing properties are capitalized.

Depreciation and Depletion - Property, plant and equipment is depreciated or depleted over its estimated life by the unit-of-production or the straight-line method. Successful exploratory wells and development costs are amortized using the unit-of-production method based on total estimated proved developed oil and gas reserves. Producing leasehold, platform costs, asset retirement costs and acquisition costs of proved properties are amortized using the unit-of-production method based on total estimated proved reserves. Non-oil and gas assets are depreciated using the straight-line method over their estimated useful lives.

Retirements and Sales - The cost and related depreciation, depletion and amortization reserves are removed from the respective accounts upon retirement or sale of property, plant and equipment. The resulting gain or loss is included in other income (expense) in the Consolidated Statement of Operations.

Interest Capitalized - The company capitalizes interest costs on major projects that require an extended period of time to complete. Interest capitalized in 2004, 2003 and 2002 was $13 million, $10 million and $8 million, respectively.

Asset Impairments

Proved oil and gas properties are reviewed for impairment on a field-by-field basis when facts and circumstances indicate that their carrying amounts may not be recoverable. In performing this review, future cash flows are estimated by applying future oil and gas prices to future production quantities, less future expenditures necessary to develop and produce the reserves. If the sum of these estimated future cash flows (undiscounted and without interest charges) is less than the carrying amount of the property, an impairment loss is recognized for the excess of the property's carrying amount over its estimated fair value based on estimated discounted future cash flows.

Other assets are reviewed for impairment by asset group for which the lowest level of independent cash flows can be identified, with impairment loss determined in a similar manner as for proved oil and gas properties.

Gain or Loss on Assets Held for Sale

Assets are classified as held for sale when the company commits to a plan to sell the assets, the sale is probable and is expected to be completed within one year. Upon transfer to the held-for-sale category, long-lived assets are no longer depreciated or depleted. A loss is recognized at the time of transfer, and subsequently thereafter, based on the difference between fair value less costs to sell and the assets' carrying value. Losses may be reversed up to the original carrying value as estimates are revised; however, any gains above the assets' original carrying value are only recognized upon disposition.

Investments in Marketable Securities

Investments in marketable securities are classified as either "trading" or "available for sale" depending on management's intent. These securities are carried in the Consolidated Balance Sheet at their estimated fair values based on quoted market prices. Unrealized gains or losses on trading securities are recognized in earnings, while unrealized gains or losses on available-for-sale securities are recorded as a component of other comprehensive income (loss) within stockholders' equity. Realized gains and losses are determined using the average cost method and are reflected as a component of other income (expense) in the Consolidated Statement of Operations. Investments in debt securities are carried as current assets or as a component of investments, derivatives and other assets, depending on their contractual maturities.

Goodwill and Other Intangible Assets

Goodwill is initially measured as the excess of the purchase price of an acquired entity over the fair values of individual assets acquired and liabilities assumed. Goodwill and certain indefinite-lived intangibles are not amortized but are reviewed annually for impairment, or more frequently if impairment indicators arise. The annual test for goodwill impairment was completed in the second quarter of 2004, with no impairment indicated. Intangibles with finite lives are amortized over their estimated useful lives. Intangibles subject to amortization are reviewed for impairment whenever impairment indicators are present.

Derivative Instruments and Hedging Activities

The company accounts for all derivative financial instruments in accordance with FASB Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities" (FAS No. 133) Derivative financial instruments are recorded as assets or liabilities in the Consolidated Balance Sheet, measured at fair value. When available, quoted market prices are used in determining fair value; however, if quoted market prices are not available, the company estimates fair value using either quoted market prices of financial instruments with similar characteristics or other valuation techniques.

The company uses futures, forwards, options, collars and swaps to reduce the effects of fluctuations in crude oil and natural gas prices, foreign currency exchange rates and interest rates. Unrealized gains or losses due to changes in the fair value of instruments that are designated as cash flow hedges and that qualify for hedge accounting under the provisions of FAS No. 133 are recorded in accumulated other comprehensive income (loss). Realized hedging gains or losses are recognized in earnings in the periods during which the hedged forecasted transactions affect earnings. The ineffective portion of the change in fair value of such hedges, if any, is included in current earnings. Derivative instruments that are not designated as hedges or that do not meet the criteria for hedge accounting and those designated as fair-value hedges under FAS No. 133 are recorded in the Consolidated Balance Sheet at fair value, with gains or losses reported currently in earnings (together with offsetting gains or losses on the hedged item for fair value hedges).

Cash flows associated with derivative instruments are included in the same category in the Consolidated Statement of Cash Flows as the cash flows from the item being hedged, unless a derivative instrument includes an other-than-insignificant financing element at inception, in which case associated cash flows are reflected in cash flows from financing activities.

Environmental Remediation and Other Contingencies

As sites of environmental concern are identified, the company assesses the existing conditions, claims and assertions, generally related to former operations, and records an estimated undiscounted liability when environmental assessments and/or remedial efforts are probable and the associated costs can be reasonably estimated. Estimates of environmental liabilities, which include the cost of investigation and remediation, are based on a variety of matters, including, but not limited to, the stage of investigation, the stage of the remedial design, evaluation of existing remediation technologies, and presently enacted laws and regulations. In future periods, a number of factors could significantly change the company's estimate of environmental remediation costs, such as changes in laws and regulations, revisions to the remedial design, unanticipated construction problems, identification of additional areas or volumes of contamination, and changes in costs of labor, equipment and technology.

To the extent costs of investigation and remediation are recoverable from the U.S. government under Title X and under certain insurance policies and such recoveries are deemed probable, the company records a receivable for the estimated amounts recoverable (undiscounted). Receivables are reflected in the Consolidated Balance Sheet as either accounts receivable or as a component of investments, derivatives and other assets, depending on estimated timing of collection.

Asset Retirement Obligations

In June 2001, the FASB issued Statement No. 143, "Accounting for Asset Retirement Obligations" (FAS No. 143). FAS No. 143 requires that an asset retirement obligation (ARO) associated with the retirement of a tangible long-lived asset be recognized as a liability in the period in which it is incurred or becomes determinable (as defined by the standard), with an associated increase in the carrying amount of the related long-lived asset. The cost of the tangible asset, including the asset retirement cost, is depreciated over the useful life of the asset. The company adopted the new standard on January 1, 2003, as discussed further in Note 16.

In accordance with the provisions of FAS No. 143, the company accrues an abandonment liability associated with its oil and gas wells and platforms when those assets are placed in service. Generally, the company does not recognize an asset retirement obligation associated with its operating chemical facilities, either because no legal obligation exists or the life of such facilities is indeterminate. However, if a decision to decommission a facility is made and the timing of liability settlement becomes known, a liability is recognized and the remaining asset retirement cost is depreciated over the remaining useful life of the assets. The ARO is recorded at its estimated fair value and accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value. Fair value is measured using expected future cash outflows discounted at the company's credit-adjusted risk-free interest rate. No market risk premium has been included in the company's calculation of ARO balances since no reliable estimate can be made by the company.

Employee Stock-Based Compensation

Stock Options - FAS No. 123, "Accounting for Stock-Based Compensation," prescribes a fair-value method of accounting for employee stock options. Following this method, compensation expense is measured based on the estimated fair value of stock options at the grant date and recognized over the vesting period. The company, however, chooses to account for its stock option plans under the optional intrinsic-value method of Accounting Principles Board Opinion (APB) No. 25, "Accounting for Stock Issued to Employees," whereby no compensation expense is generally recognized for fixed-price stock options with an exercise price equal to the fair value of the stock on the grant date.

If compensation expense for stock option grants had been determined in accordance with FAS 123, the resulting expense would have affected stock-based compensation expense, net income (loss) and per-share amounts as shown in the following table. These amounts may not be representative of future compensation expense using the fair-value method of accounting for employee stock options as the number of options granted in a particular year may not be indicative of the number of options granted in future years.

(Millions of dollars, except per share amounts)	**2004**	2003	2002
Net income (loss) as reported	**$404**	$219	$(485)
Add: stock-based employee compensation expense included in reported net income (loss), net of taxes	**11**	7	4
Deduct: stock-based compensation expense determined using a fair-value method, net of taxes	**(24)**	(23)	(19)
Pro forma net income (loss)	**$391**	$203	$(500)
Net income (loss) per share –			
Basic -			
As reported	**$3.20**	$2.18	$(4.84)
Pro forma	**3.09**	2.03	(4.99)
Diluted -			
As reported	**$3.11**	$2.17	$(4.84)
Pro forma	**3.01**	2.03	(4.99)

The fair value of each option granted in 2004, 2003 and 2002 was estimated as of the date of the grant using the Black-Scholes option pricing model with the following weighted-average assumptions:

	Assumptions				Weighted-Average
	Risk-Free Interest Rate	Expected Dividend Yield	Expected Life (years)	Expected Volatility	Fair Value of Options Granted
2004	3.5%	3.6%	5.8	22.6%	$ 8.63
2003	3.6	3.3	5.8	32.7	11.09
2002	4.8	3.4	5.8	36.0	16.97

Restricted Stock - The value of restricted stock and stock opportunity shares is equal to the market price on the grant date and is recorded as deferred compensation at the date of grant. Deferred compensation, a component of stockholders' equity, is amortized ratably over the vesting periods of the underlying grants, which range from three to five years, or over the service period, if shorter.

Employee Stock Ownership Plan (ESOP) - The company has a leveraged ESOP plan with both sponsor and third-party financing. Third-party financing is included in debt balances in the accompanying Consolidated Balance Sheet, while sponsor financing is excluded. The company stock owned by the ESOP trust is held in a loan suspense account. Deferred compensation, representing the unallocated ESOP shares, is reflected as a reduction of stockholders' equity. The company's matching contributions and dividends on the shares held by the ESOP trust are used to repay the debt, and stock is released from the loan suspense account as the principal and interest are paid. The expense is recognized and stock is then allocated to participants' accounts at market value as the participants' contributions are made to the Savings Investment Plan (SIP). Dividends paid on the common stock held in participants' accounts are also used to repay the loans, and stock with a value equal to the amount of dividends is allocated to participants' accounts. All ESOP shares are considered outstanding for earnings per share calculations. Dividends on ESOP shares are charged to retained earnings.

Revenue Recognition

Revenue derived from product sales is recognized when delivery occurs and title and risk of loss pass to the customer and collection of the resulting receivable is probable. Oil and gas sales involving balancing arrangements among partners are recognized as revenues when the oil or gas is sold using the entitlements method of accounting based on the company's net working interest and a receivable or deferred revenue is recorded for any imbalance. At December 31, 2004 and 2003, both the quantity and dollar amount of oil and gas balancing arrangements were immaterial.

Shipping and Handling Fees and Costs

All amounts billed to a customer in a sales transaction related to shipping and handling represent revenues earned and are reported as revenue. Costs incurred by the company for shipping and handling, including transportation costs paid to third-party shippers to transport oil and gas production, are reported as an expense.

Income Taxes

Deferred income taxes are provided to reflect the future tax consequences of temporary differences between the tax basis of assets and liabilities and their reported amounts in the financial statements, except for deferred taxes on income considered to be permanently reinvested in certain foreign subsidiaries.

New/Revised Accounting Standards

The Financial Accounting Standards Board (FASB) has proposed an amendment to Statement No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies" (FAS No. 19) that may change the way oil and gas producers account for deferred exploratory drilling costs. Under the current rules, there is a presumption that all exploratory drilling costs will be expensed within one year following completion of drilling if proved reserves have not been recorded, except for costs related to areas where additional exploration wells are necessary to justify development plans *and* such additional wells are under way or firmly planned for the near future. Application of FAS No. 19 to the facts and circumstances commonly faced by oil and gas producers in today's exploration and development environment (particularly in deepwater and international areas) has become a concern for the industry and there are diverse views in practice. For example, in the case of deepwater discoveries, additional appraisal wells are almost never under way or firmly planned when the drilling rig is released due to the time required to assess the initial discovery well, update geologic models, and plan appraisal well locations in an extremely high-cost drilling environment.

The new standard would relax the one-year limitation, so long as oil and gas reserves have been discovered and an enterprise "is making sufficient progress assessing the reserves and the economic and operating viability of the project." The FASB staff has developed indicators to help determine whether sufficient progress is being made. The company believes the adoption of the proposed amendment (once finalized) will have no impact on its consolidated financial statements. Additional information related to exploratory drilling costs is included in Note 31.

In December 2004, the FASB issued FASB Staff Position No. FAS 109-2 (FSP No. 109-2), "Accounting and Disclosure Guidance for the Foreign Earnings Repatriation Provisions within the American Jobs Creation Act of 2004" (the Jobs Act). FSP No. 109-2 provides guidance with respect to reporting the potential impact of the repatriation provisions of the Jobs Act on an enterprise's income tax expense and deferred tax liability. The Jobs Act was enacted on October 22, 2004, and provides for a temporary 85% dividends received deduction on certain foreign earnings repatriated during a one-year period. The deduction would result in an approximate 5.25% federal tax rate on the repatriated earnings. Additionally, withholding taxes may be due in certain tax jurisdictions. To qualify for the deduction, the earnings must be reinvested in the United States pursuant to a domestic reinvestment plan established by a company's chief executive officer and approved by a company's board of directors. Certain other criteria in the Jobs Act must be satisfied as well. FSP No. 109-2 states that an enterprise is allowed time beyond the financial reporting period to evaluate the effect of the Jobs Act on its plan for reinvestment or repatriation of foreign earnings. The company has not yet completed its evaluation of the impact of the repatriation provisions of the Jobs Act. Accordingly, as provided for in FSP No. 109-2, the company has not adjusted its tax expense or deferred tax liability to reflect the repatriation provisions of the Jobs Act. Additional disclosures related to the status of our evaluation of the Jobs Act repatriation provisions are included in Note 15.

In December 2004, the FASB issued FASB Staff Position 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," indicating that this deduction, which will be available to the company in 2005, should be accounted for as a special deduction in accordance with the provisions of FAS No. 109, as opposed to a tax-rate reduction. Beginning in 2005, the company will recognize the allowable deductions as qualifying activity occurs.

In December 2004, the FASB issued Statement No. 123 (revised 2004), "Share-Based Payment" (FAS No. 123R), which replaces FAS No. 123 and supersedes APB Opinion No. 25, "Accounting for Stock Issued to Employees. "FAS No. 123R requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on their fair values beginning with the first interim period after June 15, 2005, with early adoption encouraged. The pro forma disclosures previously permitted under FAS No. 123 no longer will be an alternative to financial statement recognition. The company is required to adopt FAS No. 123R in the third quarter of 2005. Under FAS No. 123R, the company must determine the appropriate fair value model to be used for valuing share-based payments, the amortization method for compensation cost and the transition method to be used at the date of adoption. The permitted transition methods include either retrospective or prospective adoption. Under the retrospective method of adoption, prior periods may be restated either as of the beginning of the year of adoption (modified retrospective method) or for all periods presented. The prospective method requires that compensation expense be recorded for all unvested share-based compensation awards at the beginning of the first quarter of adoption of FAS No. 123R, while the retrospective methods would record compensation expense for all unvested share-based compensation awards beginning with the first period presented. The company is currently evaluating the requirements of FAS No. 123R and expects to adopt this standard using either the prospective or the modified retrospective method of adoption. The company expects that the effect of adoption will not have a material effect on our financial condition and cash flows, and that the effect on our results of operations will be comparable to the current pro forma disclosures under FAS No. 123 included in Note 1 to the Consolidated Financial Statements.

2. Business Combination

On June 25, 2004, Kerr-McGee completed a merger with Westport Resources Corporation (Westport), an independent oil and gas exploration and production company with operations in the Rocky Mountain, Mid-Continent and Gulf Coast areas onshore U.S. and in the Gulf of Mexico. The merger increased Kerr-McGee's proved reserves by approximately 30%, bringing the combined company's total reserves as of December 31, 2003, to approximately 1.3 billion barrels of oil equivalent had the merger occurred at that date (unaudited).

On the effective date of the merger, each issued and outstanding share of Westport common stock was converted into .71 shares of Kerr-McGee common stock. As a result, Kerr-McGee issued 48.9 million shares of common stock to Westport's stockholders valued at $2.4 billion based on Kerr-McGee's weighted average stock price two days before and after the merger was publicly announced. Kerr-McGee also exchanged 1.9 million stock options for options held by Westport employees with a fair value of $34 million, determined using the Black-Scholes option pricing model.

On June 25, 2004, after completion of the merger, Kerr-McGee paid down all outstanding borrowings under the Westport revolving credit facility and the facility was terminated on July 13, 2004.

During June 2004, Kerr-McGee purchased Westport 8.25% Notes with an aggregate principal amount of $14 million ($16 million fair value). On July 1, 2004, Kerr-McGee issued a notice of redemption for the remaining 8.25% Westport notes and the notes were redeemed on July 31, 2004, at an aggregate redemption price of $786 million. The redemption price consisted of the face value of $700 million, less the amount previously purchased by Kerr-McGee of $14 million, plus a make-whole premium of $100 million.

On July 1, 2004, Kerr-McGee issued $650 million of 6.95% notes due July 1, 2024, with interest payable semi-annually. The notes were issued at 99.2%, resulting in a discount of $5 million, which will be recognized as additional interest expense over the term of the notes. The proceeds from this debt issuance, together with proceeds from borrowings under the company's revolving credit facilities, were used to redeem the 8.25% Westport notes discussed above.

In exchange for Westport's common stock and options, Kerr-McGee issued stock valued at $2.4 billion, options valued at $34 million and assumed debt of $1 billion, for a total of $3.5 billion (net of $43 million of cash acquired). The fair value assigned to assets acquired and goodwill totaled $4.7 billion. Westport's assets and liabilities are reflected in the company's balance sheet at December 31, 2004, and Westport's results of operations are included in the company's statement of operations from June 25, 2004. The purchase price was allocated to specific assets and liabilities based on their estimated fair values at the merger date, with $839 million recorded as goodwill and $596 million recorded for net deferred tax liabilities.

The strategic benefits of the merger and the principal factors that contributed to Kerr-McGee recognizing goodwill are as follows:

- Provides complementary high-quality assets in core U.S. onshore and Gulf of Mexico regions;
- Enhances the stability of high-margin production;
- Expands low-risk exploitation opportunities;
- Increases free cash flow for Kerr-McGee's high-potential exploration opportunities;
- Reduces leverage and enables greater financial flexibility; and
- Provides opportunities for synergies and related cost savings.

The condensed balance sheet information presented below shows the allocation of purchase price to Westport's assets and liabilities as of the merger date.

Condensed Balance Sheet

(Millions of dollars)

Assets	
Current Assets	
Cash and cash equivalents	$ 43
Accounts receivable	122
Derivative assets	2
Other current assets	29
Deferred income taxes	87
Total Current Assets	283
Property, Plant & Equipment:	
Proved oil and gas properties	2,370
Unproved oil and gas properties	1,064
Other assets	60
Total Property, Plant & Equipment	3,494
Derivative Assets	4
Transportation Contracts	35
Goodwill	839
Total Assets	$4,655
Liabilities and Stockholders' Equity	
Current Liabilities	
Accounts payable and accrued liabilities	$ 206
Derivative liabilities	154
Total Current Liabilities	360
Long-Term Debt	1,046
Deferred Income Taxes	683
Asset Retirement Obligations	70
Derivative Liabilities	48
Total Noncurrent Liabilities	1,847
Stockholders' Equity	2,448
Total Liabilities and Stockholders' Equity	$4,655

The pro forma information presented below has been prepared to give effect to the Westport merger as if it had occurred at the beginning of the periods presented. The pro forma information is presented for illustrative purposes only and is based on estimates and assumptions deemed appropriate by Kerr-McGee. If the Westport merger had occurred in the past, Kerr-McGee's operating results would have been different from those reflected in the pro forma information below; therefore, the pro forma information should not be relied upon as an indication of the operating results that Kerr-McGee would have achieved if the merger had occurred at the beginning of each period presented. The pro forma information also should not be used as an indication of the future results that Kerr-McGee will achieve after the Westport merger.

	Pro Forma Information (Unaudited)	
	Year Ended December 31,	
(Millions of dollars, except per-share amounts)	**2004**	2003
Revenues	**$5,607**	$4,808
Income from Continuing Operations	**476**	307
Net Income	**465**	258
Income per Common Share -		
Basic	**$ 3.10**	$ 1.73
Diluted	**3.03**	1.71

3. Other Comprehensive Income (Loss)

Components of other comprehensive income (loss) for the years ended December 31, 2004, 2003 and 2002 are as follows:

(Millions of dollars)	**2004**	2003	2002
Foreign currency translation adjustments	**$ 22**	$ 56	$ 48
Reclassification of foreign currency translation adjustment to net income	**7**	–	–
Unrealized gain (loss) on cash flow hedges, net of taxes of $296, $124 and $55	**(531)**	(203)	(93)
Reclassification of realized (gain) loss on cash flow hedges to net income, net of taxes of $(267), $(94) and $(33)	**462**	172	54
Unrealized gain on available-for-sale securities, net of taxes of $(3) and $(4) in 2003 and 2002	**–**	6	7
Reclassification of realized gain on available-for-sale securities, net of taxes of $3 and $3 in 2004 and 2003	**(5)**	(7)	–
Minimum pension liability adjustments, net of taxes of $(7), $5 and $9	**11**	(7)	(14)
	$ (34)	$ 17	$ 2

Components of accumulated other comprehensive loss at December 31, 2004 and 2003, net of applicable tax effects, are as follows:

(Millions of dollars)	**2004**	2003
Foreign currency translation adjustments	**$ 91**	$ 62
Unrealized loss on cash flow hedges	**(157)**	(88)
Unrealized gain on available-for-sale securities	**–**	5
Minimum pension liability adjustments	**(13)**	(24)
	$ (79)	$(45)

4. Cash Flow Information

Net cash provided by operating activities reflects cash payments for income taxes and interest as follows:

(Millions of dollars)	**2004**	2003	2002
Income tax payments	**$154**	$115	$ 89
Less refunds received	**(19)**	(49)	(268)
Net income tax payments (refunds)	**$135**	$ 66	$(179)
Interest payments	**$260**	$237	$ 258

Other noncash items included in the reconciliation of net income (loss) to net cash provided by operating activities include the following:

(Millions of dollars)	**2004**	2003	2002
Increase in fair value of embedded options in the DECS [(1)]	**$101**	$ 88	$ 34
Increase in fair value of trading securities [(1)]	**(103)**	(96)	(61)
Stock-based compensation	**25**	42	20
Pension and postretirement expense	**36**	44	(12)
Litigation reserves	**8**	8	75
Equity in net losses of equity method investees	**26**	33	25
Unrealized loss (gain) from nonhedge derivatives	**12**	5	(19)
Noncash spar rental expense	**14**	8	12
All other [(2)]	**41**	(38)	2
Total	**$160**	$ 94	$ 76

Details of changes in other assets and liabilities within the operating section of the Consolidated Statement of Cash Flows are as follows:

(Millions of dollars)	**2004**	2003	2002
Environmental expenditures	**$ (99)**	$(104)	$(128)
Reimbursements of environmental expenditures	**50**	15	–
Cash abandonment expenditures	**(17)**	(17)	(48)
Employer contributions to pension and postretirement plans	**(67)**	(29)	(24)
All other [(2)]	**(11)**	5	(2)
Total	**$(144)**	$(130)	$(202)

(1) See Note 11 for a discussion of the accounting for the DECS.

(2) No other individual item is material to total cash flows from operating activities.

Information about noncash investing and financing activities not reflected in the Consolidated Statement of Cash Flows follows:

(Millions of dollars)	**2004**	2003	2002
Noncash investing activities:			
Increase in property, plant and equipment [(2)]	**$3,494**	$ –	$ –
Increase (decrease) in property related to Gunnison operating lease agreement [(3)]	**(83)**	83	–
Increase in intangible assets [(2)]	**35**	–	–
Trading securities used for redemption of long-term debt [(4)]	**(586)**	–	
Increase in fair value of securities available for sale [(1)]	**–**	9	11
Investment in equity affiliate	**–**	–	2
Noncash financing activities:			
Issuance of common stock and stock options [(2)]	**2,448**	–	–
Long-term debt assumed [(2)]	**1,046**	–	–
Increase (decrease) in debt related to Gunnison operating lease agreement [(3)]	**(75)**	75	–
Long-term debt redeemed with trading securities [(4)]	**(330)**	–	–
Settlement of DECS derivative [(4)]	**(256)**	–	–
Increase in valuation of the DECS [(1)]	**–**	8	8

(1) See Note 11 for a discussion of the accounting for the DECS.
(2) Noncash transaction related to the Westport merger, see Note 2.
(3) See Note 14 for a discussion of the Gunnison lease.
(4) See Note 7 for a discussion of the redemption of the DECS.

5. **Accounts Receivable Sales**

In December 2000, the company began an accounts receivable monetization program for its pigment business through the sale of selected accounts receivable with a three-year, credit-insurance-backed asset securitization program. On July 30, 2003, the company restructured the existing accounts receivable monetization program to include the sale of receivables originated by the company's European chemical operations. During the third quarter of 2004, the company completed its renewal of the program, extending the term through July 27, 2005. The maximum availability under the program is $165 million. Under the terms of the program, selected qualifying customer accounts receivable are sold monthly to a special-purpose entity (SPE), which in turn sells an undivided ownership interest in the receivables to a third-party multi-seller commercial paper conduit sponsored by an independent financial institution. The company sells, and retains an interest in, excess receivables to the SPE as over-collateralization for the program. The company's retained interest in the SPE's receivables is classified in trade accounts receivable in the accompanying Consolidated Balance Sheet. The retained interest is subordinate to, and provides credit enhancement for, the conduit's ownership interest in the SPE's receivables, and is available to the conduit to pay certain fees or expenses due to the conduit, and to absorb credit losses incurred on any of the SPE's receivables in the event of termination. However, the company believes that the risk of credit loss is very low since its bad-debt experience has historically been insignificant. The company retains servicing responsibilities and receives a servicing fee of 1.07% of the receivables sold for the period of time outstanding, generally 60 to 120 days. No recourse obligations were recorded since the company has no obligations for any recourse actions on the sold receivables. The company also holds preference stock in the SPE, which essentially represents a retained deposit to provide further credit enhancements, if needed, but is otherwise recoverable by the company at the end of the program. The carrying value of our investment in the preference stock was $4 million at December 31, 2004 and 2003.

The program includes a ratings downgrade trigger in the event Kerr-McGee's corporate senior unsecured debt rating falls below BBB- by S&P or Baa3 by Moody's, or in the event such rating has been suspended or withdrawn by S&P or Moody's. The result of the downgrade trigger is an increase in the cost of the program, along with other program modifications. In addition, the program includes a ratings downgrade termination event, upon which the program effectively liquidates over time and the third-party multi-seller commercial paper conduit is repaid by the collections on accounts receivable sold by the SPE. The ratings downgrade termination event is triggered if Kerr-McGee's corporate senior unsecured debt (i) is rated less than BBB- by S&P and Baa3 by Moody's, (ii) is rated less than BB+ by S&P or Ba1 by Moody's or (iii) is withdrawn or suspended by S&P or Moody's.

During 2004, 2003 and 2002, the company sold $1.1 billion, $836 million and $609 million, respectively, of its pigment receivables, resulting in pretax losses of $8 million, $5 million and $5 million, respectively. The losses are equal to the difference in the book value of the receivables sold and the total of cash and the fair value of the deposit retained by the special-purpose entity. Both at year-end 2004 and 2003, the outstanding balance on receivables sold, net of the company's retained interest in receivables serving as over-collateralization, totaled $165 million. The outstanding balance of receivables serving as over-collateralization totaled $39 million and $36 million at December 31, 2004 and 2003, respectively. There were no delinquencies as of year-end 2004.

6. **Inventories**

Major categories of inventories at December 31, 2004 and 2003 are:

(Millions of dollars)	**2004**	2003
Chemicals and other products	**$236**	$307
Materials and supplies	**85**	80
Crude oil and natural gas liquids	**8**	7
Total	**$329**	$394

7. **Financial Instruments**

The company invests in certain securities classified as available for sale or trading and holds or issues financial instruments for other than trading purposes. At December 31, 2004, the company held debt securities classified as available for sale. At December 31, 2003, the company's investments consisted of available for sale debt securities and common shares of Devon Energy Corporation (Devon stock). The company had an option to use Devon stock to repay its debt exchangeable for stock (DECS). Accounting for options embedded in the DECS is discussed in Note 11. The portion of the company's Devon stock holdings necessary to repay the DECS was classified as trading and consisted of 8.4 million shares, with the remaining shares designated as available for sale. On August 2, 2004, the company's DECS matured and were settled with the distribution of shares of Devon common stock, at which time the fair values of the embedded put and call options in the DECS were nil and $256 million, respectively, and the fair value of the 8.4 million Devon shares was $586 million. The fair value of the Devon shares less the call option liability resulted in a net asset carrying value of $330 million, which was exactly offset by the fair value of the DECS resulting in no gain or loss on redemption of the debt. The company recognized, as a component of other income (expense), a charge against earnings of $7 million related to a cumulative translation adjustment recorded prior to 1999 when the company accounted for its investment in Devon using the equity method. Under the provisions of FAS No. 52, "Foreign Currency Translation," the proportionate share of Devon's cumulative translation adjustment was removed from equity and reported in earnings in 2004, when the liquidation of the associated investment occurred.

Investments in Available-for-Sale Securities

The company has certain investments that are considered to be available for sale. At December 31, 2004 and 2003, available-for-sale securities for which fair value can be determined are as follows:

(Millions of dollars)	2004 Fair Value	2004 Cost	2004 Gross Unrealized Holding Gains	2003 Fair Value	2003 Cost	2003 Gross Unrealized Holding Gains
Equity securities	$ –	$ –	$ –	$27	$10	$ 8
U.S. government obligations	4	4	–	4	4	–
Total			$ –			$ 8

The equity securities represented the company's investment in Devon common stock. During December 2003, the company sold a portion of its Devon shares classified as available-for-sale, resulting in a pretax gain of $17 million. The remaining shares were sold in January 2004 for a pretax gain of $9 million. Proceeds from the December 2003 sales totaled $59 million ($47 million received in 2003 and $12 million received in 2004) and proceeds from the January 2004 sales totaled $27 million.

Trading Securities

The market value of 8.4 million shares of Devon stock was $483 million at December 31, 2003. Unrealized pretax gains recognized in other income (expense) in the Consolidated Statement of Operations amounted to $103 million in 2004 through the date of disposition, as discussed above, $96 million in 2003 and $61 million in 2002. These gains were partially offset by unrealized losses on the embedded options associated with the DECS of $101 million in 2004 through the date of DECS redemption, $88 million in 2003 and $34 million in 2002.

Financial Instruments for Other than Trading Purposes

In addition to the financial instruments previously discussed, the company holds or issues financial instruments for other than trading purposes. At December 31, 2004 and 2003, the carrying amount and estimated fair value of these instruments are as follows:

(Millions of dollars)	2004 Carrying Amount	2004 Fair Value	2003 Carrying Amount	2003 Fair Value
Cash and cash equivalents	$ 76	$ 76	$ 142	$ 142
Long-term receivables	24	21	95	82
Debt exchangeable for stock, excluding options	–	–	326	330
Long-term debt, excluding DECS in 2003	3,699	4,039	3,329	3,761

The carrying amount of cash and cash equivalents approximates fair value of those instruments due to their short maturity. The fair value of long-term receivables is based on discounted cash flows. The fair value of the company's long-term debt is based on the quoted market prices for the same or similar debt issues or on the current rates offered to the company for debt with the same remaining maturity. Carrying values of derivative instruments, all of which approximate their fair values, are disclosed in Note 11.

8. **Property, Plant and Equipment**

Property, plant and equipment at December 31, 2004 and 2003, is as follows:

	Gross Property		Accumulated Depreciation and Depletion		Net Property	
(Millions of dollars)	**2004**	2003 (1)	**2004**	2003 (1)	**2004**	2003 (1)
Exploration and production	**$16,730**	$12,068	**$(6,866)**	$(5,709)	**$ 9,864**	$6,359
Chemicals	**2,059**	2,006	**(1,184)**	(1,052)	**875**	954
Other	**195**	184	**(107)**	(98)	**88**	86
Total	**$18,984**	$14,258	**$(8,157)**	$(6,859)	**$10,827**	$7,399

(1) Certain prior year balances were reclassified to intangible assets. See Note 10.

9. **Deferred Charges**

Deferred charges are as follows at December 31, 2004 and 2003:

(Millions of dollars)	**2004**	2003
Prepaid pension cost	**$262**	$243
Nonqualified benefit plan deposits	**48**	35
Unamortized debt issue costs and other	**33**	39
Total	**$343**	$317

10. **Goodwill and Intangible Assets**

Goodwill and other intangible assets recorded in the Westport merger were valued at $839 million and $35 million, respectively, at the merger date.

The changes in the carrying amount of goodwill for 2003 and 2004 are as follows:

	Segment		
(Millions of dollars)	Exploration and Production	Chemical - Pigment	Total Carrying Amount
Balance, December 31, 2002:	$ 347	$ 9	$ 356
Other changes (including foreign currency translation)	(1)	2	1
Balance, December 31, 2003:	**346**	**11**	**357**
Goodwill associated with the Westport merger	**839**	**–**	**839**
Other changes (including foreign currency translation)	**–**	**1**	**1**
Balance, December 31, 2004:	**$1,185**	**$12**	**$1,197**

The changes in the carrying amount of indefinite-lived intangible assets for 2003 and 2004 are as follows:

(Millions of dollars)	Carrying Amount
Intellectual Property	
Balance at December 31, 2002:	$52
Other changes (including foreign currency translation)	3
Balance at December 31, 2003:	**55**
Impairment associated with the Savannah sulfate plant shutdown [(1)]	**(8)**
Other changes (including foreign currency translation)	**6**
Balance at December 31, 2004:	**$53**

[(1)] Refer to Note 25 for more information on the Savannah sulfate impairment.

Intangible assets subject to amortization at December 31, 2003 and 2004 are as follows:

(Millions of dollars)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Balance at December 31, 2003:			
Transportation contracts	$16	$ (9)	$ 7
Other	3	(1)	2
Total	$19	$(10)	$ 9
Balance at December 31, 2004:			
Transportation contracts	**$49**	**$(13)**	**$36**
Other	**3**	**(1)**	**2**
Total	**$52**	**$(14)**	**$38**

Intangible asset amortization expense was $6 million, $5 million and $5 million in 2004, 2003 and 2002, respectively. The estimated amortization expense for the next five years totals $26 million, ranging from $4 million to $8 million annually. The remaining weighted average amortization period for the transportation contracts is eight years.

11. Derivative Instruments

The company is exposed to market risk from fluctuations in crude oil and natural gas prices, foreign currency exchange rates, and interest rates. To reduce the impact of these risks on earnings and to increase the predictability of its cash flows, the company enters into certain derivative contracts, primarily swaps and collars for a portion of its oil and gas production, forward contracts to buy and sell foreign currencies, and interest rate swaps.

The following tables summarize the balance sheet presentation of the company's derivatives as of December 31, 2004 and 2003:

	December 31, 2004				
	Derivative Fair Value				
(Millions of dollars)	Current Asset	Long-Term Asset	Current Liability	Long-Term Liability	Deferred Gain (Loss) in AOCI[1]
Oil and gas commodity derivatives –					
Kerr-McGee positions	$54	$12	$(235)	$(188)	$(167)
Acquired Westport positions	1	1	(123)	(16)	(7)
Gas marketing-related derivatives	6	2	(6)	(2)	–
Foreign currency derivatives	20	–	(6)	–	16
Interest rate swaps	4	–	(1)	(2)	–
Other	3	–	(1)	–	1
Total derivative contracts	$88	$15	$(372)	$(208)	$(157)

	December 31, 2003				
	Derivative Fair Value				
(Millions of dollars)	Current Asset	Long-Term Asset	Current Liability	Long-Term Liability	Deferred Gain (Loss) in AOCI[1]
Oil and gas commodity derivatives	$ 8	$15	$(181)	$ –	$(105)
Gas marketing-related derivatives	8	2	(7)	(2)	–
Foreign currency derivatives	28	–	(11)	–	17
Interest rate swaps	–	15	–	–	–
DECS call option	–	–	(155)	–	–
Total derivative contracts	$44	$32	$(354)	$(2)	$ (88)

(1) Amounts deferred in accumulated other comprehensive income (AOCI) are reflected net of tax.

The following tables summarize the gain (loss) on the company's derivative instruments and its classification in the Consolidated Statement of Operations for each of the last three years:

	2004			2003			2002		
	Revenues	**Costs and Expenses**	**Other Income (Expense)**	Revenues	Costs and Expenses	Other Income (Expense)	Revenues	Costs and Expenses	Other Income (Expense)
Hedge Activity:									
Oil and gas commodity derivatives	$(748)	$ –	$ –	$(279)	$ –	$ –	$ (81)	$ –	$ –
Foreign currency derivatives	(1)	19	–	–	13	–	–	(6)	–
Interest rate swaps	–	15	–	–	11	–	–	6	–
Other	–	1	–	–	–	–	–	–	–
Total hedging contracts	(749)	35	–	(279)	24	–	(81)	–	–
Nonhedge Activity:									
Oil and gas commodity derivatives -									
Kerr-McGee positions	(10)	–	1	–	–	2	–	–	8
Acquired Westport positions	(13)	–	–	–	–	–	–	–	–
Gas marketing-related derivatives	7	–	(1)	(7)	–	(5)	(20)	–	–
DECS call option [1]	–	–	(101)	–	–	(88)	–	–	(34)
Foreign currency derivatives	–	–	(8)	–	–	(7)	–	–	1
Total nonhedge contracts	(16)	–	(109)	(7)	–	(98)	(20)	–	(25)
Total derivative contracts	$(765)	$ 35	$(109)	$(286)	$ 24	$ (98)	$(101)	$ –	$(25)

(1) As discussed in Note 7, other income (expense) also includes unrealized gains on Devon stock classified as trading.

Oil and Gas Commodity Derivatives - The company periodically enters into financial derivative instruments that generally fix the commodity prices to be received for a portion of its future oil and gas production. The fair value of the company's oil and gas commodity derivative instruments was determined based on prices actively quoted, generally NYMEX and Dated Brent prices. For derivative instruments designated as cash flow hedges, gains and losses are deferred in accumulated other comprehensive income (loss) and reclassified into earnings when the associated hedged production is sold. The company expects to reclassify net after-tax deferred losses of $52 million into earnings during the next 12 months (assuming no further changes in the fair value of the related contracts). Gains and losses for hedge ineffectiveness are recognized as a component of revenues in the Consolidated Statement of Operations and were not material for all periods presented. Realized and unrealized gains and losses arising from derivative instruments that have not been designated as hedges or that do not qualify for hedge accounting ("nonhedge derivatives") are recognized in current earnings.

Nonhedge derivative losses represent net realized and unrealized gains and losses related to crude oil and natural gas derivative instruments that have not been designated as hedges or that do not qualify for hedge accounting treatment. In the second quarter of 2004, the company entered into financial derivative instruments in the form of fixed-price swaps and costless collars relating to specified quantities of projected 2004-2006 production that was not already hedged, including unhedged production from the Westport properties. Certain crude oil and natural gas swaps covering the period from August to December 2004 were characterized initially as nonhedge derivatives since either our U.S. production (excluding Westport volumes) was already hedged or, in the case of Rocky Mountain production, the company did not have sufficient basis swaps in place to ensure that the hedges would be highly effective. Consequently, the company recognized mark-to-market losses of $10 million in earnings during the second quarter associated with these derivatives. After the Westport merger closed and with sufficient oil and gas production available, these swaps were designated as hedges and, as such, realized gains and losses thereafter were recognized in earnings when the hedged production was sold.

In connection with the Westport merger, the company recognized a $196 million net liability associated with Westport's existing commodity derivatives at the merger date (June 25, 2004). Some of these derivative instruments were designated as hedges in July 2004 in connection with the redesignation of acquisition-related derivatives described above, while others do not qualify for hedge accounting treatment. In the second quarter of 2004, a mark-to-market gain of $15 million was recognized in earnings since the value of the net derivative liability had decreased to $181 million by June 30, 2004.

Westport's derivatives in place at the merger date consisted of fixed-price oil and gas swaps, natural gas basis swaps, and costless and three-way collars. The swaps qualify for hedge accounting and were designated as hedges after the merger date. Accordingly, future realized gains and losses on those derivative instruments are reflected in earnings when the hedged production is sold. However, the costless and three-way collars – each of which was in a liability position – do not qualify for hedge accounting treatment under existing accounting standards because they represent "net written options" at the merger date. As a result, even though these collars effectively reduce commodity price risk, the company will continue to recognize mark-to-market gains and losses in earnings until the collars mature, rather than defer such amounts in accumulated other comprehensive income (loss). In the second half of 2004, the company recognized losses of $28 million associated with Westport's collars. The net derivative liability associated with these derivatives at year-end 2004 was $69 million.

In addition to the company's hedging program, Kerr-McGee holds certain gas basis swaps settling between 2005 and 2008 that were acquired in the 2001 merger with HS Resources. The company initially treated these gas basis swaps as nonhedge derivatives, with changes in fair value recognized in earnings. In 2004, the company designated those swaps settling in 2005 as hedges, since the basis swaps have been coupled with natural gas fixed-price swaps, while the remainder settling between 2006 and 2008 will continue to be treated as nonhedge derivatives. From time to time, the company also enters into basis swaps to help mitigate its exposure to localized natural gas indices by, in effect, converting that exposure to NYMEX-based pricing. To the extent such basis swaps are coupled with NYMEX natural gas fixed-price swaps, they are accounted for as hedges; otherwise, any mark-to-market gains or losses are recognized in earnings currently.

Gas Marketing-Related Derivatives - The company's marketing subsidiary, Kerr-McGee Energy Services (KMES) purchases third-party natural gas for aggregation and sale with the company's own production in the Rocky Mountain area. Under some of its marketing arrangements, KMES receives fixed prices for the sale of natural gas. Existing contracts for the physical delivery of gas at fixed prices have not been designated as hedges and are marked-to-market through earnings in accordance with FAS No. 133. KMES has entered into natural gas swaps and basis swaps that largely offset its fixed-price risk on physical contracts and lock in margins associated with the physical sales. The gains and losses on the swaps, which also are marked-to-market through earnings, substantially offset the gains and losses from the fixed-price physical delivery contracts.

Foreign Currency Derivatives - From time to time, the company enters into forward contracts to buy and sell foreign currencies. Certain of these contracts (purchases of Australian dollars and British pound sterling, and sales of euro) have been designated and have qualified as cash flow hedges of the company's anticipated future cash flows related to pigment sales, capital expenditures, raw material purchases and operating costs. These forward contracts generally have durations of less than three years. Changes in the fair value of these contracts are recorded in accumulated other comprehensive income and will be recognized in earnings in the periods during which the hedged forecasted transactions affect earnings (i.e., when the hedged forecasted pigment sales occur or operating costs are incurred, when hedged assets are depreciated in the case of a capital expenditures hedge, and upon the sale of finished inventory in the case of a hedged raw material purchase). Realized gains and losses on foreign currency derivatives are classified in the Consolidated Statement of Operations consistent with the classification of the items being hedged. In 2005, the company expects to reclassify from accumulated other comprehensive income (loss) into earnings net after-tax gains of $4 million, assuming no further changes in the fair value of the related contracts. No hedges were discontinued during 2004, and no ineffectiveness was recognized.

DECS - The company issued 5.5% notes exchangeable for common stock (DECS) in August 1999, which allowed each holder to receive between .85 and 1.0 share of Devon common stock or, at the company's option, an equivalent amount of cash at maturity in August 2004. Embedded options in the DECS provide the company a floor price on Devon's common stock of $33.19 per share (the put option). The company also had the right to retain up to 15% of the shares if Devon's stock price was greater than $39.16 per share (the DECS holders had an imbedded call option on 85% of the shares). Using the Black-Scholes valuation model, the company estimated the fair value of the put and call options and recognized gains or losses resulting from changes in their fair value in other income (expenses) in the Consolidated Statement of Operations, along with the changes in the market value of Devon stock classified as trading. As discussed in Note 7, the DECS were settled through the distribution of shares of Devon stock on August 2, 2004.

Interest Rate Derivatives - In connection with the issuance of $350 million of 5.375% notes due April 15, 2005, the company entered into an interest rate swap arrangement in April 2002. The terms of the agreement effectively change the interest the company will pay on the debt until maturity from the fixed rate to a variable rate of LIBOR plus .875%. During February 2004, the company reviewed the composition of its outstanding debt and entered into additional interest rate swaps, converting an aggregate of $566 million in fixed-rate debt to variable-rate debt. Under the interest rate swaps, $150 million of 6.625% notes due October 15, 2007, were converted to pay a variable rate of LIBOR plus 3.35%; $109 million of 8.125% notes due October 15, 2005, were converted to pay a variable rate of LIBOR plus 5.86%; and $307 million of 5.875% notes due September 15, 2006, were converted to pay a variable rate of LIBOR plus 3.1%. The company considers these swaps to be hedges against the change in fair value of the related debt as a result of interest rate changes. The swaps are carried in the Consolidated Balance Sheet at their estimated fair value. Any unrealized gain or loss on the swaps is offset by a comparable gain or loss resulting from recording changes in the fair value of the related debt. Gains and losses on interest rate swaps, along with the changes in the fair value of the related debt, are reflected in interest and debt expense in the Consolidated Statement of Operations. The critical terms of the swaps match the terms of the debt; therefore, the swaps are considered highly effective and no hedge ineffectiveness has been recognized.

12. Accrued Liabilities

Accrued liabilities at December 31, 2004 and 2003 are as follows:

(Millions of dollars)	**2004**	2003
Accrued operating expenses and exploration and development costs	**$318**	$260
Employee-related costs and benefits	**156**	141
Reserves for environmental remediation and restoration	**97**	98
Interest payable	**97**	109
Taxes, other than income taxes	**75**	37
Current asset retirement obligations	**21**	20
Other	**61**	37
Total	**$825**	$702

13. Work Force Reduction, Restructuring Provisions and Exit Activities

The following table presents a reconciliation of the beginning and ending balances of reserves for exit and restructuring activities for 2004 and 2003, with discussion of material components of the activity provided below.

	2004			2003		
(Millions of dollars)	**Total**	**Personnel Costs**	**Dismantlement and Closure**	Total	Personnel Costs	Dismantlement and Closure
Beginning balance	**$ 39**	**$ 27**	**$12**	$ 27	$ 4	$23
Westport severance/ relocation	**19**	**19**	**–**	–	–	–
Provisions	**7**	**4**	**3**	37	37	–
Payments	**(46)**	**(40)**	**(6)**	(22)	(16)	(6)
Adjustments [1]	**(1)**	**(2)**	**1**	(3)	2	(5)
Ending balance	**$ 18**	**$ 8**	**$10**	$ 39	$ 27	$12

[1] Includes foreign-currency translation adjustments related to the Antwerp, Belgium accrual.

In September 2004, the company shut down sulfate and gypsum production at its Savannah, Georgia facility. In 2004, the company recognized a pretax charge of $105 million for costs associated with the shutdown. Of the total, $68 million represented accelerated depreciation of plant assets (of which $13 million related to an asset retirement obligation recognized during the third quarter of 2004), $15 million for inventory revaluation, $8 million for impairment of intangible assets, $7 million for severance and benefit plan curtailment costs, and $7 million for other closure costs. Severance cost of $2 million was paid during 2004 and $2 million remained in the reserve at the end of the year. See Note 16 for additional discussion regarding the asset retirement obligation. The shutdown will result in the elimination of approximately 100 positions, the last of which will occur in early 2005. In addition, an $18 million charge was recognized in the third quarter of 2004 for accelerated depreciation of other plant assets at the Savannah facility that are no longer in service. The company's 2004 Consolidated Statement of Operations includes $86 million in depreciation and depletion expense, $29 million in costs and operating expenses and $8 million in asset impairments, for total pretax charges of $123 million associated with the Savannah facility.

In connection with the Westport merger discussed in Note 2, the company recognized liabilities of $19 million associated with severance and relocation costs for certain former Westport employees. Affected employees, including those remaining for transitional purposes, will be terminated no later than June 2006. Of the $19 million, approximately $18 million has been paid through year-end 2004, with about $1 million remaining in the reserve at December 31, 2004.

In September 2003, the company announced a program to reduce its U.S. nonbargaining work force through both voluntary retirements and involuntary terminations. As a result of the program, the company's eligible U.S. nonbargaining work force was reduced by approximately 9%, or 271 employees. Qualifying employees terminated under this program were eligible for enhanced benefits under the company's pension and postretirement plans, along with severance payments. The program was substantially complete by the end of 2003, with certain retiring employees staying into 2004 for transition purposes. In connection with the work force reduction, the company incurred a pretax charge of $56 million in 2003, of which $34 million was for curtailment and special termination benefits associated with the company's retirement plans and $22 million was for severance-related costs. Of the severance-related provision of $22 million, $21 million was paid and the program was completed by the end of 2004. The remaining reserve balance of $1 million, representing an excess of estimated provisions over actual costs, was reversed in the fourth quarter of 2004.

During 2003, the company's chemical - pigment operating unit provided $61 million pretax for costs associated with the closure of its synthetic rutile plant in Mobile, Alabama. Included in the $61 million were $14 million for the cumulative effect of change in accounting principle related to the recognition of an asset retirement obligation, $15 million for accelerated depreciation, $15 million for other closure costs, $11 million for severance benefits and $6 million for benefit plan curtailment costs. Additionally, in 2004, $7 million was provided by the company for additional costs associated with the plant closure, of which $4 million relates to accelerated depreciation of additional asset retirement costs and $1 million to environmental remediation costs. See Note 16 for a discussion of the related asset retirement obligation. The reserve balance related to this plant closure was $2 million at the end of 2004 and 2003. Approximately 127 employees will ultimately be terminated in connection with this plant closure, of which 111 had been terminated as of December 31, 2004. Payments are expected to continue through the end of 2007.

During 2002, the company's chemical - other operating unit provided $17 million for costs associated with exiting its forest products business. Additional provisions of $5 million and $2 million were recorded in 2003 and 2004, respectively, for a total of $24 million over the three-year period. Of this amount, $18 million was provided for dismantlement and closure costs, and $6 million for severance costs. Through December 31, 2004, $17 million had been paid, with $7 million remaining in the reserve at year-end. Payments related to the plant closures are expected to continue for several years in connection with dismantlement and cleanup efforts; however, all of the severance costs are expected to be paid by the end of March 2005. The company operated its fifth plant, a leased facility located in The Dalles, Oregon, through December 2004. In January 2005, the assets located at The Dalles were sold. In connection with the plant closures, approximately 235 employees will be terminated, of which 216 were terminated as of year-end 2004. In addition to the provisions for severance, dismantlement and closure, the company recognized $9 million in 2003 and $8 million in 2004 for other costs associated with the shutdown. The 2003 costs included accelerated depreciation on plant assets, curtailment costs and special termination benefits related to pension and postretirement plans, while 2004 costs represented operating costs during the shutdown period. As discussed in Note 25, in the fourth quarter of 2004, criteria for presenting results of operations of the forest products business as discontinued operations have been met. Therefore, the provisions for plant closures discussed above are included in income (loss) from discontinued operations for all periods presented.

In 2001, the company's chemical - pigment operating unit provided $32 million related to the closure of a plant in Antwerp, Belgium. The provision consisted of $12 million for severance costs, $12 million for dismantlement costs, $7 million for contract settlement costs and $1 million for other plant closure costs. Of this total accrual, $5 million remained in the restructuring accrual at the end of both 2004 and 2003. As a result of this plant closure, 121 employees have been terminated as of December 31, 2004. Payments related to severance are expected to continue until early 2016. Payments related to other shutdown costs could extend into 2017.

14. Debt

Lines of Credit

In November 2004, the company entered into a $1.5 billion unsecured revolving credit agreement with a term of five years. Concurrent with this transaction, the company terminated two revolving credit facilities with an aggregate maximum availability of $1.35 billion. Interest on borrowings under the new revolving credit facility may be based, at the company's option, on LIBOR, EURIBOR or on the JPMorgan prime rate. The interest rate margin varies based on the company's debt rating and facility utilization.

At year-end 2004, the company had maximum available capacity under the revolving credit facility and bank lines of credit of $1.55 billion.

The company has arrangements to maintain compensating balances with certain banks that provide credit. At year-end 2004, the aggregate amount of such compensating balances was not material, and the company was not legally restricted from withdrawing all or a portion of such balances at any time during the year.

Long-Term Debt

The company's policy is to classify certain borrowings under revolving credit facilities and commercial paper as long-term debt, since the company has the ability under certain revolving credit agreements and the intent to maintain these obligations for longer than one year. At year-end 2004 and 2003, debt totaling $41 million and nil, respectively, was classified as long-term consistent with this policy.

In connection with the Westport merger in June 2004, the company assumed $1 billion of debt, all of which was subsequently repaid. See further discussion in Note 2.

Long-term debt consisted of the following at December 31, 2004 and 2003:

(Millions of dollars)	**2004**	2003
Debentures –		
5.25% Convertible subordinated debentures due February 15, 2010 (convertible at $61.08 per share, subject to certain adjustments) [(1)]	**$ 600**	$ 600
7% Debentures due November 1, 2011, net of unamortized debt discount of $77 in 2004 and $84 in 2003 (14.25% effective rate)	**173**	166
7.125% Debentures due October 15, 2027 (7.01% effective rate)	**150**	150
Notes payable –		
Floating rate notes due June 28, 2004 (1.92% average interest rate at December 31, 2003)	**–**	100
8.375% Notes due July 15, 2004	**–**	145
5.5% Exchangeable Notes (DECS) due August 2, 2004, net of unamortized debt discount of $4 in 2003 (5.60% effective rate) (See Note 7)	**–**	326
5.375% Notes due April 15, 2005 (includes a premium of $4 in 2004 for fair value hedge adjustment)	**354**	350
8.125% Notes due October 15, 2005 (net of discount of $1 in 2004 for fair value hedge adjustment)	**108**	109
5.875% Notes due September 15, 2006 (5.89% effective rate)	**307**	307
6.625% Notes due October 15, 2007 (net of discount of $2 in 2004 for fair value hedge adjustment)	**148**	150
6.875% Notes due September 15, 2011, net of unamortized debt discount of $1 in both 2004 and 2003 (6.90% effective rate)	**674**	674
6.95% Notes due July 1, 2024, net of unamortized debt discount of $5 (7.02% effective rate)	**645**	–
7.875% Notes due September 15, 2031, net of unamortized debt discount of $2 in both 2004 and 2003 (7.91% effective rate)	**498**	498
Commercial paper (2.7% average effective interest rate at December 31, 2004)	**41**	–
Guaranteed Debt of Employee Stock Ownership Plan 9.61% Notes due in installments through January 2, 2005	**1**	5
Gunnison Trust floating rate notes due November 8, 2006 (1.93% average interest rate at December 31, 2003)	**–**	75
	3,699	3,655
Long-term debt due within one year	**(463)**	(574)
Total	**$3,236**	$3,081

Future maturities of long-term debt as of December 31, 2004, are as follows:

(Millions of dollars)	2005	2006	2007	2008	2009	There-after [(1)]	Total [(2)]
Long-term debt	$463	$307	$148	$ –	$ 41	$2,740	$3,699

(1) As discussed in Note 35, in March 2005 all of the 5.25% debentures were converted by the holders into 9.8 million shares of common stock.

(2) These amounts are inclusive of the unamortized discount on issuance of $85 million and the net fair value hedge adjustments of $(1) million.

The company's long-term debt agreements do not contain subjective acceleration clauses (commonly referred to as material adverse change clauses); however, certain of the company's long-term debt agreements contain restrictive covenants, including a maximum total debt to total capitalization ratio, as defined in the agreements, of 65%. At December 31, 2004, the company had a total debt to capitalization ratio of 41% and was in compliance with its other debt covenants. All outstanding notes and debentures are unsecured.

During 2001, the company entered into a leasing arrangement with Kerr-McGee Gunnison Trust (Gunnison Trust) for the construction of the company's share of a platform to be used in the development of the Gunnison field, in which the company has a 50% working interest. Under the terms of the agreement, the company's share of construction costs for the platform was financed under a five-year synthetic lease credit facility between the trust and groups of financial institutions for up to $157 million, with the company making lease payments sufficient to pay interest at varying rates on the notes. Construction of the platform was completed in December 2003, with the company's share of construction costs totaling $149 million. On December 31, 2003, $66 million of the synthetic lease facility was converted to a leveraged lease structure, whereby the company leases an interest in the platform under an operating lease agreement from a separate business trust.

The company adopted provisions of the FASB Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN No. 46) effective December 31, 2003. Both the Gunnison Trust and the new operating lease trust are considered variable interest entities under the provisions of FIN No. 46. As such, the company is required to analyze its relationship with each trust to determine whether the company is the primary beneficiary, and thus required to consolidate the trusts. Based on the analyses performed, the company is not the primary beneficiary of the operating lease trust; however, the company was considered the primary beneficiary of the Gunnison Trust at December 31, 2003. Accordingly, the remaining assets and liabilities of the Gunnison Trust were reflected in the company's Consolidated Balance Sheet at December 31, 2003, which included $83 million in property, plant and equipment, $4 million in accrued liabilities, $75 million in long-term debt, and $4 million in minority interest. The Gunnison Trust floating rate notes payable were secured by the platform assets of $83 million included in property, plant and equipment and an assignment of the company's lease agreement with the Gunnison Trust. The $66 million of platform assets and related debt that was converted to the leveraged lease structure in December 2003 was not recognized in the company's Consolidated Balance Sheet at December 31, 2003. On January 15, 2004, the remaining $83 million of the synthetic lease facility was converted to the leveraged lease structure, and the related lessor trust was no longer subject to consolidation. As a result, the related property and debt is not reflected in the company's Consolidated Balance Sheet at December 31, 2004. The operating lease commitment is discussed in Note 20.

15. Income Taxes

The 2004, 2003 and 2002 income tax provisions (benefits) from continuing operations are summarized below:

(Millions of dollars)	**2004**	2003	2002
U.S. Federal –			
Current	**$ 26**	$ 23	$ 13
Deferred	**83**	11	(94)
	109	34	(81)
International –			
Current	**123**	58	36
Deferred	**21**	100	10
	144	158	46
State	**3**	3	–
Total	**$256**	$195	$ (35)

In the following table, the U.S. Federal income tax rate is reconciled to the company's effective tax rates for income or loss from continuing operations as reflected in the Consolidated Statement of Operations.

	2004	2003	2002
U.S. statutory rate – provision (benefit)	**35.0%**	35.0%	(35.0)%
Increases (decreases) resulting from –			
Adjustment of deferred tax balances due to tax rate changes	**(.6)**	–	19.9
Taxation of foreign operations	**4.8**	8.6	12.1
Federal income tax credits	**–**	–	(1.8)
State income taxes	**.3**	.5	–
Other – net	**(1.3)**	(1.6)	(.8)
Total	**38.2%**	42.5%	(5.6)%

Net deferred tax liabilities at December 31, 2004 and 2003, are comprised of the following:

(Millions of dollars)	**2004**	2003
Deferred tax liabilities –		
Property, plant and equipment	**$2,444**	$1,587
Investments	**–**	170
Undistributed earnings of certain foreign subsidiaries	**28**	28
Deferred state, local and other taxes	**23**	24
Intangible assets	**31**	12
Other	**52**	92
Total deferred tax liabilities	**2,578**	1,913
Deferred tax assets –		
Net operating loss and other carryforwards	**(209)**	(206)
Derivative instruments	**(107)**	(88)
Asset retirement and environmental obligations	**(224)**	(192)
Foreign exploration expenses	**(83)**	(63)
Obligations for pension and other benefits	**(28)**	(43)
Financial accruals and deferrals	**(59)**	(59)
Other	**(23)**	(12)
	(733)	(663)
Valuation allowance associated with loss carryforwards	**8**	9
Net deferred tax assets	**(725)**	(654)
Net deferred tax liability	**$1,853**	$1,259

Taxation for a company with operations in several foreign countries involves many complex variables, such as tax structures that differ from country to country and the effect on U.S. taxation of international earnings. These complexities do not permit meaningful comparisons between the U.S. and international components of income before income taxes and the provision for income taxes, and disclosures of these components do not necessarily provide reliable indicators of relationships in future periods. Income (loss) from continuing operations before income taxes is comprised of the following:

(Millions of dollars)	**2004**	2003	2002
United States	**$339**	$161	$ (84)
International	**332**	298	(541)
Total	**$671**	$459	$(625)

On July 24, 2002, the United Kingdom government made certain changes to its existing tax laws. Under one of these changes, companies are required to pay a supplementary corporate tax charge of 10% on profits from their U.K. oil and gas production, in addition to the required 30% corporate tax on these profits. The U.K. government also accelerated tax depreciation for capital investments in U.K. upstream activities and abolished North Sea royalty. The deferred income tax liability was adjusted to reflect these changes, causing a net increase in the 2002 international deferred provision for income taxes of $132 million.

At December 31, 2004, the company had foreign operating loss carryforwards totaling $351 million. Of this amount, $13 million expires in 2006, $1 million in 2007, $106 million in 2009 and $231 million has no expiration date. Realization of these operating loss carryforwards depends on generating sufficient taxable income in future periods. A valuation allowance of $8 million has been recorded to reduce deferred tax assets associated with loss carryforwards that the company does not expect to fully realize prior to expiration.

Undistributed earnings of certain consolidated foreign subsidiaries totaled $891 million at December 31, 2004. No provision for deferred U.S. income taxes has been made for these earnings because they are considered to be indefinitely invested outside the United States. The distribution of these earnings in the form of dividends or otherwise, may subject the company to U.S. income taxes and, possibly, foreign withholding taxes. However, because of the complexities of U.S. taxation of foreign earnings, it is not practicable to estimate the amount of additional tax that might be payable on the eventual remittance of these earnings.

On October 22, 2004, the President of the United States signed the American Jobs Creation Act of 2004 (the "Act") into law. A provision of the Act includes a deduction of 85% of certain foreign earnings that are repatriated, as defined in the Act. We may elect to apply this provision to qualifying earnings repatriated during the reporting period ending December 31, 2005. We are currently evaluating the potential impact of this legislation, including assessing the details of the Act and analyzing the funds available for repatriation. However, given the preliminary status of the evaluation, we do not expect to be able to complete the analysis until after Congress or the Department of the Treasury provides additional clarifying language. Currently, the range of possible amounts that we are considering for repatriation under this provision is between zero and $500 million. The related potential range of income and foreign withholding tax for such repatriation is between zero and $29 million.

The Internal Revenue Service has completed its examination of the Kerr-McGee Corporation and subsidiaries' federal income tax returns for all years through 1998 and is conducting an examination of the years 1999 through 2002. The years through 1996 have been closed with the exception of issues for which a refund claim has been filed. The Oryx Energy Company income tax returns have been examined through 1997, and the years through 1978 have been closed, as have the years 1988 through 1997. Oryx and Kerr-McGee merged in 1999. The company believes that it has made adequate provision for income taxes that may be payable with respect to open years.

16. Asset Retirement Obligations

As discussed in Note 1, the company adopted FAS No. 143 on January 1, 2003, which resulted in an increase in net property of $108 million, an increase in abandonment liabilities of $161 million and a decrease in deferred income tax liabilities of $18 million. The net impact of these changes resulted in an after-tax charge to earnings of $35 million to recognize the cumulative effect of adopting the new standard. If the provisions of FAS No. 143 had been applied retroactively, pro forma net loss for 2002 would have been $492 million, with basic and diluted loss per share of $4.91.

A summary of the changes in the abandonment liability during 2004 and 2003 is included in the table below.

(Millions of dollars)	**2004**	2003
Balance, January 1	**$421**	$395
New obligations incurred	**30**	11
Liability assumed in the Westport merger	**79**	–
Accretion expense	**30**	25
Changes in estimates, including timing	**(16)**	22
Abandonment expenditures	**(17)**	(17)
Abandonment obligations settled through property divestitures	**(3)**	(15)
Balance, December 31	**524**	421
Less: current asset retirement obligation	**(21)**	(20)
Less: asset retirement obligation classified as held for disposal	**–**	(16)
Noncurrent asset retirement obligation	**$503**	$385

As discussed in Note 13, the company closed its synthetic rutile plant in Mobile, Alabama, in 2003. In September 2004, the company shut down sulfate and gypsum production at its Savannah, Georgia, plant. Until the decisions to shut down these facilities had been made, it was indeterminable when the asset retirement liability associated with these facilities would be settled. Upon deciding to shut down the facilities, the timing of settlement became estimable and the related asset retirement obligation was recorded at the estimated fair value. For the synthetic rutile plant in Mobile, Alabama, an $18 million liability was recognized at the beginning of 2003. For the sulfate production facility at the company's Savannah, Georgia, plant, an abandonment liability of $13 million was recognized in September 2004.

Operations at the Mobile, Alabama, facility included production of feedstock for titanium dioxide pigment plants of the company's chemical business. The facility ceased operations in June 2003. Operations prior to closure had resulted in minor contamination of groundwater adjacent to surface impoundments. A groundwater recovery system was installed prior to closure and continues in operation as required under the National Pollutant Discharge Elimination System (NPDES) permit. Future remediation work, including groundwater recovery, closure of the impoundments and other minor work, is expected to be substantially completed in about five years. As of December 31, 2004, the company had a remaining abandonment reserve of $11 million. Although actual costs may exceed current estimates, the amount of any increases cannot be reasonably estimated at this time.

An abandonment reserve related to the titanium dioxide pigment sulfate production at Savannah, Georgia, was established to address probable remediation activities, including environmental assessment, closure of certain impoundments, groundwater monitoring, asbestos abatement, and other work, which are expected to take over 25 years. As of December 31, 2004, the reserve remained at about $13 million. Although actual costs may exceed current estimates, the amount of any increase cannot be reasonably estimated at this time.

17. Noncurrent Liabilities – Other

Other noncurrent liabilities consist of the following at year-end 2004 and 2003:

(Millions of dollars)	**2004**	2003
Postretirement benefit obligations	**$209**	$215
Reserves for environmental remediation and restoration	**158**	152
Pension plan liabilities	**47**	73
Litigation reserves	**24**	32
Accrued rent for spar operating leases	**46**	32
Ad valorem taxes	**33**	31
Other	**54**	28
Total	**$571**	$563

18. Employee Benefit Plans

The company has both noncontributory and contributory defined-benefit retirement plans and company-sponsored contributory postretirement plans for health care and life insurance. Most employees are covered under the company's retirement plans, and substantially all U.S. employees may become eligible for the postretirement benefits if they reach retirement age while working for the company. Kerr-McGee uses a December 31 measurement date for its plans. In 2004, the company recognized a curtailment loss and special termination benefits associated with the shutdown of sulfate production at the Savannah, Georgia, facility. Also in 2004, the company recognized losses on settlement of certain qualified and nonqualified benefits as a result of cash settlements associated with normal retirements and retirements resulting from the 2003 work force reduction program. In 2003, the company recognized a curtailment loss with respect to pension and postretirement benefits in connection with its work force reduction program and plant closures and recognized special termination benefits associated with its work force reduction program. These losses have been reflected in the disclosures below.

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) was signed into law. The Act expands Medicare to include, for the first time, coverage for prescription drugs. The Act also introduces a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. In May 2004, the FASB issued Staff Position (FSP) FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," to provide guidance on accounting for the effects of the Act. Kerr-McGee adopted FSP FAS 106-2 in the third quarter of 2004 and, as a result, the company's accumulated postretirement benefit obligation as of July 1, 2004, the date of remeasurement, was reduced by $46 million and the third quarter 2004 net periodic postretirement cost was reduced by approximately $2 million. This reduction is reflected as an actuarial gain and is not treated as a change in plan provisions.

On November 1, 2004, the company announced that the prescription drug coverage provided by its U.S. postretirement benefit plan will become secondary to Medicare Part D effective January 1, 2006, causing the plan to no longer qualify for the federal subsidy. As a result of the plan change, the company's accumulated postretirement benefit obligation (remeasured as of November 1, 2004) was further reduced by $30 million. The combined impact of the FSP FAS 106-2 adoption and the plan change on fourth quarter 2004 net periodic postretirement cost was a reduction of expense of approximately $2 million.

On January 21, 2005, the centers for Medicare and Medicaid Services (CMS) released the final regulations (the Regulations) implementing the Act. Generally, the regulations are expected to cause more retiree health programs to meet the Act's actuarial equivalence standard. Together with our actuarial advisor, Kerr-McGee determined our plan's actuarial equivalence in mid-2004 and, as previously mentioned, adopted FSP FAS 106-2 in the third quarter of 2004. Based on review of the final regulations, the company and its actuary believe that the impact on the accumulated benefit obligation and the net periodic cost recognized in 2004 is not material.

Following are the changes in the benefit obligations during the past two years:

	Retirement Plans		Postretirement Health and Life Plans	
(Millions of dollars)	**2004**	2003	**2004**	2003
Benefit obligation, beginning of year	**$1,250**	$1,147	**$314**	$327
Service cost	**30**	25	**3**	3
Interest cost	**73**	74	**18**	17
Plan amendments/law changes	**1**	(3)	**(72)**	10
Net actuarial loss (gain)	**90**	84	**38**	(28)
Foreign exchange rate changes	**12**	17	**–**	–
Contributions by plan participants	**–**	–	**9**	9
Special termination benefits, settlement and curtailment (gains) losses	**(1)**	28	**–**	9
Benefits paid	**(195)**	(122)	**(34)**	(33)
Benefit obligation, end of year	**$1,260**	$1,250	**$276**	$314

Following are the expected benefit payments for the next five years and in the aggregate for the years 2010 through 2014:

(Millions of dollars)	2005	2006	2007	2008	2009	2010-2014
Retirement Plans	$109	$89	$100	$92	$95	$537
Postretirement Health and Life Plans	24	18	19	19	19	94

The benefit amount that can be covered by the retirement plans that qualify under the Employee Retirement Income Security Act of 1974 (ERISA) is limited by both ERISA and the Internal Revenue Code. Therefore, the company has unfunded supplemental nonqualified plans designed to maintain benefits for all employees at the plan formula level and to provide senior executives with benefits equal to a specified percentage of their final average compensation.

The following table summarizes the accumulated benefit obligations and the projected benefit obligations associated with the company's unfunded benefit plans.

	At December 31, 2004			At December 31, 2003		
(Millions of dollars)	U.S. Nonqualified Plans [1]	U.S. Postretirement Plan	Germany Retirement Plan	U.S. Nonqualified Plans [1]	U.S. Postretirement Plan	Germany Retirement Plan
Accumulated benefit obligation	**$37**	**$276**	**$12**	$41	$314	$10
Projected benefit obligation	**55**	**276**	**13**	50	314	10

[1] Although not considered plan assets, a grantor trust was established from which payments for certain U.S. supplemental benefits are made. The trust assets had a balance of $50 million at year-end 2004 and $37 million at year-end 2003.

Summarized below are the accumulated benefit obligation, the projected benefit obligation, the market value of plan assets and the funded status of the company's funded retirement plans.

	At December 31, 2004			At December 31, 2003		
(Millions of dollars)	U.S. Qualified Plan	The Netherlands Retirement Plan	U.K. Retirement Plan	U.S. Qualified Plan	The Netherlands Retirement Plan	U.K. Retirement Plan
Accumulated benefit obligation	**$ 941**	**$ 61**	**$ 73**	$ 984	$ 49	$ 63
Projected benefit obligation	**$1,034**	**$ 70**	**$ 88**	$1,063	$ 53	$ 75
Market value of plan assets	**1,109**	**59**	**79**	1,188	51	44
Funded status	**$ 75**	**$(11)**	**$ (9)**	$ 125	$ (2)	$(31)

Following are the changes in the fair value of plan assets during the past two years and the reconciliation of the plans' funded status to the amounts recognized in the financial statements at December 31, 2004 and 2003:

(Millions of dollars)	Retirement Plans 2004	Retirement Plans 2003	Postretirement Health and Life Plans 2004	Postretirement Health and Life Plans 2003
Fair value of plan assets, beginning of year	**$ 1,283**	$ 1,190	**$ –**	$ –
Actual return on plan assets	**107**	198	**–**	–
Employer contributions (1)	**42**	5	**25**	24
Participant contributions	**–**	–	**9**	9
Foreign exchange rate changes	**10**	12	**–**	–
Benefits paid	**(195)**	(122)	**(34)**	(33)
Fair value of plan assets, end of year (2)	**1,247**	1,283	**–**	–
Benefit obligation	**(1,260)**	(1,250)	**(276)**	(314)
Funded status of plans - over (under)	**(13)**	33	**(276)**	(314)
Amounts not recognized in the Consolidated Balance Sheet –				
Prior service costs	**49**	58	**(16)**	12
Net actuarial loss	**193**	106	**59**	68
Prepaid expense (accrued liability)	**$ 229**	$ 197	**$(233)**	$(234)
Accumulated benefit obligation	**$(1,124)**	$(1,147)		

(1) During 2004, the company made a discretionary contribution of approximately $26 million to the U.K. trust fund to increase plan assets above the accumulated benefit obligation level. The company expects to contribute $4 million to its U.S. nonqualified plans, $24 million to its U.S. postretirement plan and approximately $6 million to its foreign retirement plans in 2005. No contributions are expected in 2005 for the U.S. qualified retirement plan.

(2) Excludes the grantor trust assets of $50 million and $37 million at year-end 2004 and 2003, respectively, associated with the company's supplemental nonqualified U.S. plans.

Following is the classification of the amounts recognized in the Consolidated Balance Sheet at December 31, 2004 and 2003:

(Millions of dollars)	Retirement Plans 2004	Retirement Plans 2003	Postretirement Health and Life Plans 2004	Postretirement Health and Life Plans 2003
Prepaid pension cost	**$262**	$230	**$ –**	$ –
Accrued benefit liability	**(55)**	(72)	**(233)**	(234)
Additional minimum liability - intangible asset	**–**	1	**–**	–
Accumulated other comprehensive income (before tax)	**20**	38	**–**	–
Total	**$227**	$197	**$(233)**	$(234)

For 2004, 2003 and 2002, the company had after-tax gains (losses) of $11 million, $(7) million and $(14) million, respectively, included in other comprehensive income resulting from changes in the additional minimum pension liability.

Total costs recognized for employee retirement and postretirement benefit plans for each of the last three years, were as follows:

	Retirement Plans			Postretirement Health and Life Plans		
	2004	2003	2002	**2004**	2003	2002
Net periodic cost -						
Service cost	**$ 30**	$ 25	$ 24	**$ 3**	$ 3	$ 3
Interest cost	**73**	73	76	**18**	17	19
Expected return on plan assets	**(116)**	(122)	(130)	**–**	–	–
Special termination benefits, settlement and curtailment losses (1)	**14**	38	–	**–**	10	–
Net amortization -						
Prior service cost	**8**	9	10	**1**	–	1
Net actuarial (gain) loss	**3**	(9)	(16)	**2**	–	1
Total	**$ 12**	$ 14	$ (36)	**$24**	$30	$24

(1) 2004 net periodic pension cost included special termination benefit and curtailment costs associated with the shutdown of sulfate production at the Savannah, Georgia, facility and plan settlement losses related to normal retirements and retirements resulting from the 2003 work force reduction program. The 2003 period includes special termination benefit and curtailment costs associated with the shutdown of the forest products operations and the Mobile, Alabama facility and curtailment costs associated with the 2003 work force reduction program.

The following assumptions were used in estimating the net periodic expense:

	2004		2003		2002	
	United States	**International**	United States	International	United States	International
Discount rate	**6.25%(1)**	**5.25 – 5.5%**	6.75%	5.5 – 5.75%	7.25%	5.75%
Expected return on plan assets	**8.5**	**5.75 – 7.25**	8.5	5.25 – 7.25	9.0	5.75 – 7.0
Rate of compensation increases	**4.5**	**2.75 – 5.0**	4.5	2.5 – 6.5	5.0	2.5 – 7.5

(1) Following remeasurement at July 1, 2004 to recognize a settlement for the qualified plan, the discount rate for the qualified plan was 6.5% for the remainder of the year.

The following assumptions were used in estimating the actuarial present value of the plans' benefit obligations:

	2004		2003		2002	
	United States	**International**	United States	International	United States	International
Discount rate	**5.75%**	**4.75 – 5.25%**	6.25%	5.25 – 5.5%	6.75%	5.5 – 5.75%
Rate of compensation increases	**4.5**	**3.0 – 4.75**	4.5	2.75 – 5.0	4.5	2.5 – 6.5

The health care cost trend rates used to determine the year-end 2004 postretirement benefit obligation were 10% in 2005, gradually declining to 5% in the year 2010 and thereafter. A 1% increase in the assumed health care cost trend rate for each future year would increase the postretirement benefit obligation at December 31, 2004, by $14 million and increase the aggregate of the service and interest cost components of the net periodic postretirement expense for 2004 by $1 million. A 1% decrease in the trend rate for each future year would reduce the benefit obligation at year-end 2004 by $15 million and decrease the aggregate of the service and interest cost components of the net periodic postretirement expense for 2004 by $1 million.

Asset categories for the company's U.S. and foreign funded retirement plans and the weighted-average asset allocations at December 31, 2004 and 2003, by asset category are as follows:

	U.S. Plan Assets at December 31,		Foreign Plan Assets at December 31,	
	2004	2003	**2004**	2003
Equity securities	**57%**	55%	**50%**	42%
Debt securities	**41%**	41%	**46%**	57%
Cash	**2%**	4%	**4%**	1%
Total	**100%**	100%	**100%**	100%

In forming the assumption of the U.S. long-term rate of return, the company takes into account the expected earnings on funds already invested, earnings on contributions expected to be received in the current year, and earnings on reinvested returns. The long-term rate of return estimation methodology for U.S. plans is based on a capital asset pricing model using historical data. An expected return analysis is performed and updated semi-annually by a third-party consultant and incorporates the portfolio allocation, historical asset-class returns and an assessment of expected future performance using asset-class risk factors. Our assumption of the long-term rate of return for the U.K. and the Netherlands plans is based on the advice of third-party consultants, considering portfolio mix and the rates of return on local government and corporate bonds.

The company selects a discount rate assumption based on the average current yields on high quality long-term fixed income instruments. For U.S. plans, the average Moody's Long-Term AA Corporate Bond Yield and the Citigroup Pension Liability Index are used as a guide in the selection of the discount rate. For foreign plans, the company bases the discount rate assumption on local corporate bond index rates.

The U.S. plan is administered by a board-appointed committee that has fiduciary responsibility for the plan's management. The committee maintains an investment policy stating the guidelines for the performance and allocation of plan assets, performance review procedures and updating of the policy. At least annually, the U.S. plan's asset allocation guidelines are reviewed in light of evolving risk and return expectations. Current guidelines permit the committee to manage the allocation of funds between equity and debt securities at its discretion; however, throughout 2003 and 2004, the committee has maintained an allocation of assets in the range of 40-60% equity securities and 40-60% debt securities.

Substantially all of the plan's assets are invested with eight equity fund managers and six fixed-income fund managers. At year-end 2004 and 2003, equity securities held by the plan included $3 million and $2 million of Kerr-McGee stock, respectively, or 50,737 shares. Dividends paid on these shares were less than $100,000 in 2004 and 2003. To control risk, equity fund managers are prohibited from entering into the following transactions, (i) investing in commodities, including all futures contracts, (ii) purchasing letter stock, (iii) short selling and (iv) option trading. In addition, equity fund managers are prohibited from purchasing on margin and are prohibited from purchasing Kerr-McGee securities. Equity managers are monitored to ensure investments are in line with their style and are generally permitted to invest in U.S. common stock, U.S. preferred stock, U.S. securities convertible into common stock, common stock of foreign companies listed on major U.S. exchanges, common stock of foreign companies listed on foreign exchanges, covered call writing, and cash and cash equivalents.

Fixed-income fund managers are prohibited from investing in (i) foreign debt securities, (ii) direct real estate mortgages or commingled real estate funds, (iii) private placements above certain portfolio thresholds, (iv) tax exempt debt of state and local governments above certain portfolio thresholds, (v) fixed income derivatives that would cause leverage, (vi) guaranteed investment contracts, and (vii) Kerr-McGee securities. They are permitted to invest in debt securities issued by the U.S. government, its agencies or instrumentalities, commercial paper rated A1/P1, FDIC insured certificates of deposit or bankers acceptances, and corporate debt obligations. All securities held in fixed-income fund manager accounts must be rated no less than Baa3 or its equivalent and each fund manager's portfolio should have an average credit rating of A or better.

The Netherlands plan is administered by a pension committee representing the employer, the employees and the pensioners, each with one equal vote. The pension committee members are approved by the state's lead pension agency based upon experience and character. The pension committee meets at least quarterly to discuss regulatory changes, asset performance and asset allocation. The plan assets are managed by one Dutch fund manager against a mandate set at least annually by the pension committee. Annually the plan assets are evaluated by a multinational benefits consultant against state defined actuarial tests to determine funding requirements.

The company's U.K. plan is administered by a board of six trustees; four of whom are appointed by the company and two who are elected by the plan's membership. Meetings of the trustees are held at least quarterly to discuss pension-related issues. The trustees are assisted by external advisers who provide advice on legal, funding and investment allocation matters.

19. Contingencies

The following table summarizes the contingency reserve balances, provisions, payments and settlements for 2002, 2003 and 2004, as well as balances, accruals and receipts of reimbursements of environmental costs from other parties.

(Millions of dollars)	Legal Reserves	Reserves for Environmental Remediation [1]	Total Contingency Reserves	Reimbursements Receivable
Balance, December 31, 2001	$ 46	$ 182	$ 228	$ –
Provisions / Accruals	75	202	277	113
Payments / Settlements	(48)	(126)	(174)	–
Balance, December 31, 2002	73	258	331	113
Provisions / Accruals	8	94	102	32
Payments / Settlements	(44)	(104)	(148)	(15)
Balance, December 31, 2003	**37**	**248**	**285**	**130**
Provisions / Accruals	**15**	**106**	**121**	**14**
Payments / Settlements	**(13)**	**(99)**	**(112)**	**(50)**
Balance, December 31, 2004	**$ 39**	**$ 255**	**$ 294**	**$ 94**

[1] Provisions for environmental remediation and restoration in 2002, 2003 and 2004 include $27 million, $2 million and $6 million, respectively, related to the company's forest products operations. These charges are reflected in the Consolidated Statement of Operations as a component of income (loss) from discontinued operations.

Management believes, after consultation with general counsel, that currently the company has reserved adequately for the reasonably estimable costs of environmental matters and other contingencies. However, additions to the reserves may be required as additional information is obtained that enables the company to better estimate its liabilities, including liabilities at sites now under review, though the company cannot now reliably estimate the amount of future additions to the reserves. Following are discussions regarding certain environmental sites and litigation. Reserves for each environmental site are based on assumptions regarding the volumes of contaminated soils and groundwater involved, as well as associated excavation, transportation and disposal costs.

The company provides for costs related to contingencies when a loss is probable and the amount is reasonably estimable. It is not possible for the company to reliably estimate the amount and timing of all future expenditures related to environmental and legal matters and other contingencies because, among other reasons:

- some sites are in the early stages of investigation, and other sites may be identified in the future;
- remediation activities vary significantly in duration, scope and cost from site to site depending on the mix of unique site characteristics, applicable technologies and regulatory agencies involved;
- cleanup requirements are difficult to predict at sites where remedial investigations have not been completed or final decisions have not been made regarding cleanup requirements, technologies or other factors that bear on cleanup costs;
- environmental laws frequently impose joint and several liability on all potentially responsible parties, and it can be difficult to determine the number and financial condition of other potentially responsible parties and their respective shares of responsibility for cleanup costs;
- environmental laws and regulations, as well as enforcement policies, are continually changing, and the outcome of court proceedings and discussions with regulatory agencies are inherently uncertain;
- some legal matters are in the early stages of investigation or proceeding or their outcomes otherwise may be difficult to predict, and other legal matters may be identified in the future;
- unanticipated construction problems and weather conditions can hinder the completion of environmental remediation; the inability to implement a planned engineering design or use planned technologies and excavation methods may require revisions to the design of remediation measures, which delay remediation and increase costs; and the identification of additional areas or volumes of contamination and changes in costs of labor, equipment and technology generate corresponding changes in environmental remediation costs.

West Chicago, Illinois

In 1973, the company's chemical affiliate (Chemical) closed a facility in West Chicago, Illinois, that processed thorium ores for the federal government and for certain commercial purposes. Historical operations had resulted in low-level radioactive contamination at the facility and in surrounding areas. The original processing facility is regulated by the State of Illinois (the State), and four vicinity areas are designated as Superfund sites on the National Priorities List (NPL).

Closed Facility – Pursuant to agreements reached in 1994 and 1997 among Chemical, the City of West Chicago (the City) and the State regarding the decommissioning of the closed West Chicago facility, Chemical has substantially completed the excavation of contaminated soils and has shipped those soils to a licensed disposal facility. Surface restoration was completed in 2004, except for areas designated for use in connection with the Kress Creek and Sewage Treatment Plant remediation discussed below. Groundwater monitoring and remediation is expected to continue for approximately 10 years.

Vicinity Areas – The Environmental Protection Agency (EPA) has listed four areas in the vicinity of the closed West Chicago facility on the NPL and has designated Chemical as a Potentially Responsible Party (PRP) in these four areas. Chemical has substantially completed remedial work for two of the areas (known as the Residential Areas and Reed-Keppler Park). The other two NPL sites, known as Kress Creek and the Sewage Treatment Plant, are contiguous and involve low levels of insoluble thorium residues, principally in streambanks and streambed sediments, virtually all within a floodway. Chemical has reached an agreement in principle with the appropriate federal and state agencies and local communities regarding the characterization and cleanup of the sites, past and future government response costs, and the waiver of natural resource damages claims. The agreement in principle is expected to be incorporated in a consent decree, which must be agreed to by the appropriate federal and state agencies and local communities and then entered by a federal court. It is anticipated that the consent decree will be filed with the court in 2005 and approved by the court in due course thereafter. Chemical has already conducted an extensive characterization of Kress Creek and the Sewage Treatment Plant and, at the request of EPA, Chemical is conducting limited additional characterization that is expected to be completed in early 2005. The cleanup work, which is expected to take about four years to complete following entry of the consent decree, will require excavation of contaminated soils and stream sediments, shipment of excavated materials to a licensed disposal facility and restoration of affected areas.

Financial Reserves – In 2004, $28 million was added to the reserve for the West Chicago site to cover increased soil volumes encountered at the closed facility, anticipated groundwater remediation the company believes will be required following soil removal at the closed facility and increased soil volumes at Kress Creek. As of December 31, 2004, the company had reserves of $100 million for costs related to West Chicago. Although actual costs may exceed current estimates, the amount of any increase cannot be reasonably estimated at this time. The amount of the reserve is not reduced by reimbursements expected from the federal government under Title X of the Energy Policy Act of 1992 (Title X) (discussed below).

Government Reimbursement – Pursuant to Title X, the U.S. Department of Energy (DOE) is obligated to reimburse Chemical for certain decommissioning and cleanup costs incurred in connection with the West Chicago sites in recognition of the fact that about 55% of the facility's production was dedicated to U.S. government contracts. The amount authorized for reimbursement under Title X is $365 million plus inflation adjustments. That amount is expected to cover the government's full share of West Chicago cleanup costs. Through December 31, 2004, Chemical had been reimbursed approximately $215 million under Title X.

Reimbursements under Title X are provided by congressional appropriations. Historically, congressional appropriations have lagged Chemical's cleanup expenditures. As of December 31, 2004, the government's share of costs incurred by Chemical but not yet reimbursed by the DOE totaled approximately $79 million. The company believes receipt of the remaining arrearage in due course following additional congressional appropriations is probable and has reflected the arrearage as a receivable in the financial statements. Approximately $49 million of the $79 million arrearage was received during the first quarter of 2005, with additional funds expected to be received later in 2005. The company will recognize recovery of the government's share of future remediation costs for the West Chicago sites as Chemical incurs the cash expenditures.

Henderson, Nevada

In 1998, Chemical decided to exit the ammonium perchlorate business. At that time, Chemical curtailed operations and began preparation for the shutdown of the associated production facilities in Henderson, Nevada, that produced ammonium perchlorate and other related products. Manufacture of perchlorate compounds began at Henderson in 1945 in facilities owned by the U.S. government. The U.S. Navy expanded production significantly in 1953 when it completed construction of a plant for the manufacture of ammonium perchlorate. The Navy continued to own the ammonium perchlorate plant as well as other associated production equipment at Henderson until 1962, when the plant was purchased by a predecessor of Chemical. The ammonium perchlorate produced at the Henderson facility was used primarily in federal government defense and space programs. Perchlorate has been detected in nearby Lake Mead and the Colorado River.

Chemical began decommissioning the facility and remediating associated perchlorate contamination, including surface impoundments and groundwater when it decided to exit the business in 1998. In 1999 and 2001, Chemical entered into consent orders with the Nevada Division of Environmental Protection that require Chemical to implement both interim and long-term remedial measures to capture and remove perchlorate from groundwater.

In 1999, Chemical initiated the interim measures required by the consent orders. Construction of a long-term remediation system is complete, and the system is operating in compliance with the consent orders. While the remediation system currently is projected to operate through 2007, the scope, duration and cost of groundwater remediation will be driven in the long term by drinking water standards, which to date have not been formally established by state or federal regulatory authorities. EPA and other federal and state agencies currently are evaluating the health and environmental risks associated with perchlorate as part of the process for ultimately setting drinking water standards. One state agency, the California Environmental Protection Agency (CalEPA), has set a public health goal for perchlorate, and the federal EPA has established a reference dose for perchlorate, which are preliminary steps to setting drinking water standards. The establishment of drinking water standards could materially affect the scope, duration and cost of the long-term groundwater remediation that Chemical is required to perform.

Financial Reserves – Remaining reserves for Henderson totaled $10 million as of December 31, 2004. As noted above, the long-term scope, duration and cost of groundwater remediation are uncertain and, therefore, additional costs beyond those accrued may be incurred in the future. However, the amount of any additional costs cannot be reasonably estimated at this time.

Litigation – In 2000, Chemical initiated litigation against the United States seeking contribution for response costs. The suit is based on the fact that the government owned the plant in the early years of its operation, exercised significant control over production at the plant and the sale of products produced at the plant, and was the largest consumer of products produced at the plant. The discovery stage of litigation is substantially complete, and the parties have filed certain pretrial motions that are being considered by the court. Although the outcome of the litigation is uncertain, Chemical believes it is likely to recover a portion of its costs from the government. The amount and timing of any recovery cannot be estimated at this time and, accordingly, the company has not recorded a receivable or otherwise reflected in the financial statements any potential recovery from the government.

In addition, on July 26, 2004, the company was served with a lawsuit, which was filed in the United States District Court for the District of Arizona. The lawsuit, Alan Curtis and Linda Curtis v. City of Bullhead City, et al., in which the company is one of several defendants (the Defendants), alleges various causes of action under a variety of common law theories and federal environmental laws and seeks recovery for damages allegedly caused by the alleged exposure to and the migration of various chemical contaminants contained in the Colorado River. The two plaintiffs, who are not suing on behalf of any other party, also seek an order requiring the Defendants to remediate the contamination. The company intends to vigorously defend against the lawsuit. The company believes that the litigation will not have a material adverse effect on its financial condition or results of operations.

Insurance – In 2001, Chemical purchased a 10-year, $100 million environmental cost cap insurance policy for groundwater and other remediation at Henderson. The insurance policy provides coverage only after Chemical exhausts a self-insured retention of approximately $61 million and covers only those costs incurred to achieve a cleanup level specified in the policy. As noted above, federal and state agencies have not established a drinking water standard and, therefore, it is possible that Chemical may be required to achieve a cleanup level more stringent than that covered by the policy. If so, the amount recoverable under the policy could be affected.

At December 31, 2004, expenditures incurred to date of approximately $67 million plus remaining costs to be incurred of approximately $9 million exceed the self-insured retention, resulting in an expected insurance reimbursement of about $15 million based on current cost estimates. The company believes that the reimbursement is probable and, accordingly, the company has recorded a receivable in the financial statements of $15 million.

Milwaukee, Wisconsin

In 1976, Chemical closed a wood-treatment facility it had operated in Milwaukee, Wisconsin. Operations at the facility prior to its closure had resulted in the contamination of soil and groundwater at and around the site with creosote and other substances used in the wood-treatment process. In 1984, EPA designated the Milwaukee wood-treatment facility as a Superfund site under CERCLA, listed the site on the NPL and named Chemical a PRP. Chemical executed a consent decree in 1991 that required it to perform soil and groundwater remediation at and below the former wood-treatment area and to address a tributary creek of the Menominee River that had become contaminated as a result of the wood-treatment operations. Actual remedial activities were deferred until after the decree was finally entered in 1996 by a federal court in Milwaukee.

Groundwater treatment was initiated in 1996 to remediate groundwater contamination below and in the vicinity of the former wood-treatment area. It is not possible to reliably predict how groundwater conditions will be affected by soil removal in the vicinity of the former wood-treatment area, which has been completed, and ongoing groundwater treatment; therefore, it is not known how long groundwater treatment will continue. Soil cleanup of the former wood-treatment area began in 2000 and was completed in 2002. Also in 2002, terms for addressing the tributary creek were agreed upon with EPA, after which Chemical began the implementation of a remedy to reroute the creek and to remediate associated sediment and stream bank soils. Completion of the creek remedy is expected to take about three more years.

Financial Reserves – In 2004, $4 million was added to the reserves for the excavation and disposal of additional soil volumes encountered during remediation of the tributary creek of the Menominee River. As of December 31, 2004, the company had reserves of $6 million for the costs of the remediation work described above. Although actual costs may exceed current estimates, the amount of any increases cannot be reasonably estimated at this time.

Cushing, Oklahoma

In 1972, an affiliate of the company closed a petroleum refinery it had operated near Cushing, Oklahoma. Prior to closing the refinery, the affiliate also had produced uranium and thorium fuel and metal at the site pursuant to licenses issued by the Atomic Energy Commission (AEC). The uranium and thorium operations commenced in 1962 and were shut down in 1966, at which time the affiliate decommissioned and cleaned up the portion of the facility related to uranium and thorium operations to applicable standards. The refinery also was cleaned up to applicable standards at the time of closing.

Subsequent regulatory changes required more extensive remediation at the site. In 1990, the affiliate entered into a consent agreement with the State of Oklahoma to investigate the site and take appropriate remedial actions related to petroleum refining and uranium and thorium residuals. Investigation and remediation of hydrocarbon contamination is being performed with oversight of the Oklahoma Department of Environmental Quality. Soil remediation to address hydrocarbon contamination is expected to continue for about four more years. The long-term scope, duration and cost of groundwater remediation are uncertain and, therefore, additional costs beyond those accrued may be incurred in the future.

Additionally, in 1993, the affiliate received a decommissioning license from the Nuclear Regulatory Commission (NRC), the successor to AEC's licensing authority, to perform certain cleanup of uranium and thorium residuals. All known radiological contamination has been removed from the site and shipped to a licensed disposal facility.

Financial Reserves – In 2004, $17 million was added to the reserves primarily for groundwater treatment, excavation, disposal of contaminated soil and costs attributable to the final stages of the radiological cleanup at Cushing. As of December 31, 2004, the company had reserves of $21 million for the costs of the ongoing remediation and decommissioning work described above. Although actual costs may exceed current estimates, the amount of any increases cannot be reasonably estimated at this time.

New Jersey Wood-Treatment Site

In 1999, EPA notified Chemical and its parent company that they were PRPs at a former wood-treatment site in New Jersey that has been listed by EPA as a Superfund site. At that time, the company knew little about the site as neither Chemical nor its parent had ever owned or operated the site. A predecessor of Chemical had been the sole stockholder of a company that owned and operated the site. The company that owned the site already had been dissolved and the site had been sold to a third party before Chemical became affiliated with the former stockholder in 1964. Actual costs incurred by EPA through 2004 were approximately $164 million.

There are substantial uncertainties about Chemical's responsibility for the site, and Chemical is evaluating possible defenses to any claim by EPA for response costs. EPA has not articulated the factual and legal basis on which EPA notified Chemical and its parent that they are potentially responsible parties. The EPA notification may be based on a successor liability theory premised on the 1964 transaction pursuant to which Chemical became affiliated with the former stockholder of the company that had owned and operated the site. Based on available historical records, it is uncertain whether and, if so, under what terms the former stockholder assumed liabilities of the dissolved company. Moreover, as noted above, the site had been sold to a third party and the company that owned and operated the site had been dissolved before Chemical became affiliated with that company's stockholder. In addition, there appear to be other PRPs, though it is not known whether the other parties have received notification from EPA. EPA has not ordered Chemical or its parent to perform work at the site and is instead performing the work itself. The company has not recorded a reserve for the site as it is not possible to reliably estimate the liability Chemical or its parent may have for the cleanup because of the aforementioned uncertainties and the existence of other PRPs.

Los Angeles County, California

During the second quarter of 2004, the company began remediation and restoration of an oil and gas field in Los Angeles County, California. The company's obligation for remediation and restoration of this oil and gas field is expected to take about five years. In 2004, $25 million was added to the reserve based on the results of engineering studies and subsequent field experience at the site, which indicated that soil volumes requiring remediation were greater than initially anticipated. As of December 31, 2004, the company had environmental reserves of $25 million for this project. Although actual costs may exceed current estimates, the amount of any increase cannot be reasonably estimated at this time.

Other Sites

In addition to the sites described above, the company is responsible for environmental costs related to certain other sites. These sites relate primarily to wood-treating, chemical production, landfills, mining and oil and gas production and refining distribution and marketing. As of December 31, 2004, the company had remaining reserves of $93 million for the environmental costs in connection with these other sites. This includes the remaining portion of $32 million added to the reserves in 2004 primarily because additional remediation, characterization and/or monitoring costs were identified for certain of these sites. Although actual costs may exceed current estimates, the amount of any increase cannot be reasonably estimated at this time.

Coal Supply Contract

An affiliate of the company entered into a coal supply contract with Peabody Coaltrade, Inc. ("PCI") in February 1998. In 1998, the company exited the coal business and assigned its rights and obligations under the coal supply contract to a third party. In connection with the assignment, the company agreed to guarantee performance under the contract. PCI has notified the company of a threatened default by the assignee under the coal supply contract and that PCI may seek to hold the company liable under the 1998 guaranty in the event of a default. In addition to other defenses to the enforceability of the guaranty, the company believes the guaranty expired in January 2003 when the primary term of the coal supply contract expired. No reserve has been provided for performance under the guaranty because the company does not believe a loss is probable and the amount of any loss is not reasonably estimable.

CNR Contract

In 2002, an affiliate of the company entered into a contract with CNR International ("CNR") to sell certain assets located in the United Kingdom sector of the North Sea. In the fourth quarter of 2004, CNR asserted claims for alleged breaches of contractual representations and warranties and demanded damages. The company's evaluation of the claims is in its early stages. The company has not provided a reserve for the claims because at this time the company cannot reasonably determine the probability of a loss and the amount of loss, if any, cannot be reasonably estimated. The company does not expect the resolution of the claims to have a material adverse effect on the company's financial condition or results of operations.

Forest Products Litigation

Between 1999 and 2001, Chemical and its parent company were named in 22 lawsuits in three states (Mississippi, Louisiana and Pennsylvania) in connection with present and former forest products operations located in those states (in Columbus, Mississippi; Bossier City, Louisiana; and Avoca, Pennsylvania). The lawsuits sought recovery under a variety of common law and statutory legal theories for personal injuries and property damages allegedly caused by exposure to and/or release of creosote and other substances used in the wood-treatment process. Chemical has executed settlement agreements that are expected to resolve substantially all of the Louisiana, Pennsylvania and Columbus, Mississippi, lawsuits described above. Accordingly most of the suits have been, or are expected to be, dismissed.

Following the adoption by the Mississippi legislature of tort reform, plaintiffs' lawyers filed many new lawsuits across the state of Mississippi in advance of the reform's effective date. On December 31, 2002, approximately 245 lawsuits were filed against Chemical and its affiliates on behalf of approximately 4,600 claimants in connection with Chemical's Columbus, Mississippi, operations, seeking recovery on legal theories substantially similar to those advanced in the litigation described above. Substantially all of these lawsuits have been removed to the U.S. District Court for the Northern District of Mississippi, and the court has consolidated these lawsuits for pretrial and discovery purposes. On December 31, 2002, June 13, 2003, and June 25, 2004, three lawsuits were filed against Chemical in connection with a former wood-treatment plant located in Hattiesburg, Mississippi. On September 9, 2004, February 11, 2005, and March 2, 2005, three lawsuits were filed against Chemical in connection with a former wood-treatment plant located in Texarkana, Texas. In addition, on January 3, 2005, and February 16, 2005, 30 lawsuits were filed against Chemical in connection with the Avoca, Pennsylvania facility described above. These lawsuits seek recovery on legal theories substantially similar to those advanced in the litigation described above. A total of approximately 3,300 claimants now have asserted claims in connection with the Hattiesburg plant, there are 63 plaintiffs named in the Texarkana lawsuits and approximately 4,600 plaintiffs are named in the new Avoca lawsuits. Chemical has resolved approximately 1,490 of the Hattiesburg claims pursuant to a settlement reached in April 2003, which has resulted in aggregate payments by Chemical of approximately $600,000.

Chemical and its affiliates believe that the follow-on Columbus and Avoca claims, the remaining Hattiesburg claims and the claims related to the Texarkana plants are without substantial merit and are vigorously defending against them. The company has not provided a reserve for these lawsuits because at this time it cannot reasonably determine the probability of a loss, and the amount of loss, if any, cannot be reasonably estimated. The company believes that the ultimate resolution of the forest products litigation will not have a material adverse effect on the company's financial condition or results of operations.

Other Matters

The company and/or its affiliates are parties to a number of legal and administrative proceedings involving environmental and/or other matters pending in various courts or agencies. In the ordinary course of its business, the company experiences disputes with federal, state, tribal and other regulatory authorities, as well as with private parties, regarding royalty payments. These disputes, individually and in the aggregate, are not expected to have a material adverse effect on the company. These are also proceedings associated with facilities currently or previously owned, operated or used by the company's affiliates and/or their predecessors, some of which include claims for personal injuries and property damages. Current and former operations of the company's affiliates also involve management of regulated materials and are subject to various environmental laws and regulations. These laws and regulations will obligate the company's affiliates to clean up various sites at which petroleum and other hydrocarbons, chemicals, low-level radioactive substances and/or other materials have been contained, disposed of or released. Some of these sites have been designated Superfund sites by EPA pursuant to CERCLA. Similar environmental regulations exist in foreign countries in which the company's affiliates operate.

20. **Commitments**

Lease Obligations and Guarantees

The company has various commitments under noncancelable operating lease agreements, principally for office space, production and gathering facilities and other equipment. The company has also entered into operating lease agreements for the use of the Nansen, Boomvang and Gunnison platforms located in the Gulf of Mexico. Aggregate minimum annual rentals under all operating leases (including the platform leases in effect at December 31, 2004), total $823 million, of which $69 million is due in 2005, $66 million in 2006, $60 million in 2007, $60 million in 2008, $49 million in 2009 and $519 million thereafter. Total lease rental expense was $84 million in 2004, $65 million in 2003 and $61 million in 2002. Subsequent to December 31, 2004, an office space lease was renegotiated resulting in additional annual rentals totaling

$16 million of which nil is due in 2005, $1 million in each of the years 2006 through 2009 and $12 million thereafter.

During 2001, the company entered into a synthetic lease arrangement with Kerr-McGee Gunnison Trust for the construction of the company's share of a platform to be used in the development of the Gulf of Mexico Gunnison field, in which the company has a 50% working interest. The company's portion of platform construction costs was financed with a $149 million synthetic lease between the trust and a group of financial institutions. Completion of the Gunnison platform occurred in December 2003, at which time a portion of the platform assets was acquired by a separate business trust and the company entered into an operating lease for the use of the assets. The remaining portion of the Gunnison synthetic lease was converted to an operating lease on January 15, 2004. See Note 14 for discussion regarding the application of provisions of FIN 46 to the Gunnison Trust and operating lease.

The company has guaranteed that the Nansen, Boomvang and Gunnison platforms will have residual values at the end of the operating leases equal to at least 10% of the fair value of the platform at the inception of the lease. For Nansen and Boomvang, the guaranteed values are $14 million and $8 million, respectively, in 2022, and for Gunnison the guarantee is $15 million in 2024.

During 2003 and 2002, the company entered into sale-leaseback arrangements with General Electric Capital Corporation (GECC) covering assets associated with a gas-gathering system in the Wattenberg field. The lease agreements were entered into for the purpose of monetizing certain of the gathering system assets. The sales price for the 2003 equipment was $6 million. The sales price for the 2002 equipment was $71 million; however, an $18 million settlement obligation existed for equipment previously covered by the lease agreement, resulting in net cash proceeds of $53 million in 2002. The 2002 operating lease agreements have an initial term of five years, with two 12-month renewal options, and the company may elect to purchase the equipment at specified amounts after the end of the fourth year. The 2003 operating lease agreement has an initial term of four years, with two 12-month renewal options. In the event the company does not purchase the equipment and it is returned to GECC, the company may be required to make payments in connection with residual value guarantees ranging from $35 million at the end of the initial terms to $27 million at the end of the last renewal option. The company recorded no gain or loss associated with the GECC sale-leaseback agreements. The future minimum annual rentals due under noncancelable operating leases shown above include payments related to these agreements.

In conjunction with the company's sale of its Ecuadorean assets, which included the company's nonoperating interest in the Oleoducto de Crudos Pesados Ltd. (OCP) pipeline, the company has entered into a performance guarantee agreement with the buyer for the benefit of OCP. Under the terms of the agreement, the company guarantees payment of any claims from OCP against the buyer upon default by the buyer and its parent company. Claims generally would be for the buyer's proportionate share of construction costs of OCP; however, other claims may arise in the normal operations of the pipeline. Accordingly, the amount of any such future claims cannot be reasonably estimated. In connection with this guarantee, the buyer's parent company has issued a letter of credit in favor of the company up to a maximum of $50 million, upon which the company can draw in the event it is required to perform under the guarantee agreement. The company will be released from this guarantee when the buyer obtains a specified credit rating as stipulated under the guarantee agreement.

In connection with certain contracts and agreements, the company has entered into indemnifications related to title claims, environmental matters, litigation and other claims. The company has recorded no material obligations in connection with its indemnification agreements.

Purchase Obligations

In the normal course of business, the company enters into contractual agreements to purchase raw materials, pipeline capacity, utilities and other services. Aggregate future payments under these contracts total $1.1 billion, of which $409 million is expected to be paid in 2005, $264 million in 2006, $201 million in 2007, $88 million in 2008, $36 million in 2009, and $122 million thereafter.

Drilling Rig Commitments

During 2004, the company entered into arrangements to participate in the use of various drilling rigs. The commitment with respect to these arrangements totals up to $117 million, depending on partner utilization. These agreements extend through 2005. Subsequent to December 31, 2004, the company entered into additional agreements totaling $31 million, of which $21 million is due in 2005 and $10 million is due in 2006.

Letters of Credit and Other

At December 31, 2004, the company had outstanding letters of credit in the amount of approximately $106 million. Most of these letters of credit have been granted by financial institutions to support our international drilling commitments.

As discussed in Notes 1 and 16, the company has obligations associated with the retirement of tangible long-lived assets. In addition to asset retirement obligations reflected in the company's Consolidated Balance Sheet, obligations exist for certain chemical facilities that are not estimable until the timing of settlement is known and, therefore, have not been reflected in the consolidated financial statements.

21. Capital Stock

Authorized capital stock of the company consists of 300 million shares of common stock, par value of $1.00 per share, and 40 million shares of preferred stock without par value. No shares of preferred stock have been issued. In June 2004, the company issued 48.9 million shares of its common stock in connection with its merger with Westport (see Note 2).

Changes in common stock issued and treasury stock held for 2004, 2003 and 2002 are as follows:

(Thousands of shares)	Common Stock	Treasury Stock
Balance at December 31, 2001	100,186	1
Exercise of stock options	112	–
Issuance of restricted stock	94	(5)
Forfeiture of restricted stock	(2)	11
Issuance of shares for achievement awards	1	–
Balance at December 31, 2002	100,391	7
Exercise of stock options	18	–
Issuance of restricted stock	483	–
Forfeiture of restricted stock	–	25
Balance at December 31, 2003	100,892	32
Shares issued in Westport merger	48,949	–
Exercise of stock options	1,725	–
Issuance of restricted stock	483	–
Forfeiture of restricted stock	–	128
Balance at December 31, 2004	152,049	160

There are 1,107,692 shares of the company's common stock registered in the name of a wholly owned subsidiary of the company. These shares are not included in the number of shares shown in the preceding table or in the Consolidated Balance Sheet. These shares are not entitled to be voted.

At December 31, 2004, approximately 2.6 million shares of common stock were reserved for issuance pursuant to the company's long-term incentive plans, and approximately 9.8 million shares of common stock were issuable upon conversion of outstanding 5.25% convertible debentures. As discussed in Note 14, in March 2005 all of the debentures were converted by the holders into 9.8 million shares of common stock.

Preferred Share Purchase Rights Plan – The company has had a stockholders' rights plan since 1986. The current rights plan is dated July 26, 2001, and replaced the previous plan prior to its expiration. Rights were distributed as a dividend at the rate of one right for each share of the company's common stock and continue to trade together with each share of common stock. Generally, the rights become exercisable the earlier of 10 days after a public announcement that a person or group has acquired, or a tender offer has been made for, 15% or more of the company's then-outstanding stock. If either of these events occurs, each right would entitle the holder (other than a holder owning more than 15% of the outstanding stock) to buy the number of shares of the company's common stock having a market value two times the exercise price. The exercise price is $215. Generally, the rights may be redeemed at $.01 per right until a person or group has acquired 15% or more of the company's stock. The rights expire in July 2006.

22. Employee Stock-Based Compensation Plans

The 2002 Long-Term Incentive Plan (2002 Plan) authorizes the issuance of shares of the company's common stock any time prior to May 13, 2012, in the form of stock options, restricted stock or performance awards. The options may be accompanied by stock appreciation rights, none of which were outstanding at December 31, 2004 and 2003. Upon the exercise of stock appreciation rights, the associated options are surrendered. A total of 7,000,000 shares of the company's common stock is authorized to be issued under the 2002 Plan, of which a maximum of 1,750,000 shares of common stock is authorized for issuance in connection with awards of restricted stock and performance awards. Performance awards may be granted in the form of performance shares or performance units. Performance shares define a benefit to the grantee by reference to shares of stock, while performance units provide for cash awards based on the company's achievement of certain financial performance measures over a stated period. There were 19 million and 11 million performance units outstanding at December 31, 2004 and 2003, respectively. Compensation expense associated with these awards was not material for all periods presented.

In January 1998, the Board of Directors approved a broad-based stock option plan (BSOP) that provides for the granting of options to purchase the company's common stock to full-time, nonbargaining-unit employees, except officers. A total of 1,500,000 shares of common stock is authorized to be issued under the BSOP at any time prior to December 31, 2007.

The 1987 Long-Term Incentive Program (1987 Program), the 1998 Long-Term Incentive Plan (1998 Plan) and the 2000 Long-Term Incentive Plan (2000 Plan) authorized the issuance of shares of the company's stock in the form of stock options, restricted stock or long-term performance awards. The 1987 Program was terminated when the stockholders approved the 1998 Plan, the 1998 Plan was terminated with the approval of the 2000 Plan, and the 2000 Plan was terminated with the approval of the 2002 Plan. No options could be granted under the 1987 Program, the 1998 Plan or the 2000 Plan after each plan's respective termination date, although options and any accompanying stock appreciation rights outstanding may be exercised prior to their expiration dates.

Stock Options - The company's employee stock options are fixed-price options granted at the fair market value of the underlying common stock on the date of the grant. Generally, one-third of each grant vests and becomes exercisable over a three-year period immediately following the grant date and expires 10 years after the grant date. As discussed in Note 2, on June 25, 2004, the company completed its merger with Westport. In connection with the merger, the company exchanged Westport options outstanding as of the merger date for Kerr-McGee options based on the exchange factor set forth in the merger agreement.

The following table summarizes the stock option transactions during 2004, 2003 and 2002 under the compensation plans described above and in connection with the Westport merger:

	2004		2003		2002	
	Options	**Weighted-Average Exercise Price per Option**	Options	Weighted-Average Exercise Price per Option	Options	Weighted-Average Exercise Price per Option
Outstanding, beginning of year	**6,418,719**	**$56.02**	5,406,424	$59.27	3,433,745	$61.18
Options issued in Westport merger	**1,901,988**	**29.55**	–	–	–	–
Options granted	**1,385,536**	**49.45**	1,353,100	42.93	2,544,562	57.08
Options exercised	**(1,744,179)**	**32.42**	(18,500)	44.55	(111,411)	46.78
Options forfeited	**(183,545)**	**47.26**	(189,638)	55.35	(141,116)	58.42
Options expired	**(261,864)**	**60.99**	(132,667)	57.78	(319,356)	67.09
Outstanding, end of year	**7,516,655**	**53.63**	6,418,719	56.02	5,406,424	59.27
Exercisable, end of year	**4,636,210**	**56.89**	3,382,550	59.81	2,179,960	59.60

The following table summarizes information about stock options issued under the plans described above that are outstanding and exercisable at December 31, 2004:

Options Outstanding				Options Exercisable	
Options	Range of Exercise Prices per Option	Weighted-Average Remaining Contractual Life (years)	Weighted-Average Exercise Price per Option	Options	Weighted-Average Exercise Price per Option
328,125	$15.00 – $29.99	5.4	$26.53	230,674	$25.95
64,425	30.00 – 39.99	4.0	33.45	57,801	33.46
2,743,893	40.00 – 49.99	8.1	46.10	572,724	43.11
1,644,756	50.00 – 59.99	5.4	55.15	1,287,661	55.42
2,621,156	60.00 – 69.99	5.3	63.59	2,373,050	63.81
111,956	70.00 – 79.99	2.1	72.66	111,956	72.66
2,344	90.00 – 99.99	1.4	98.62	2,344	98.62
7,516,655		6.3	53.63	4,636,210	56.89

Restricted Stock - Restricted stock is awarded in the name of the employee and, except for the right of disposal, holders have full shareholders' rights during the period of restriction, including voting rights and the right to receive dividends. Under the 2002 Plan, certain key employees in Europe and Australia have received stock opportunity grants giving them the opportunity to earn unrestricted stock in the future, provided that certain conditions are met. These stock opportunity grants do not carry voting privileges or dividend rights since the related shares are not issued until vested. Restricted stock and stock opportunity grants generally vest between three and five years. The company granted 483,000, 483,000 and 99,000 shares of restricted common stock in 2004, 2003 and 2002, for which the weighted average fair value at the date of grant was $22 million, $20 million and $4 million, respectively. The company granted 7,000 and 9,000 stock opportunity shares in 2004 and 2003, the fair value of which was not material. There were no stock opportunity grants issued in 2002. Compensation expense associated with restricted stock and stock opportunity awards was $17 million, $10 million and $6 million in 2004, 2003, and 2002, respectively.

Employee Stock Ownership Plan - In 1989, the company's Board of Directors approved a leveraged Employee Stock Ownership Plan (ESOP) into which the company's matching contribution for the employees' contributions to the Kerr-McGee Corporation Savings Investment Plan (SIP) is paid. The ESOP was amended in 2001 to provide matching contributions for the employees' contributions made to the Kerr-McGee Pigments (Savannah) Inc., Employees' Savings Plan, a savings plan for the bargaining-unit employees at the company's Savannah, Georgia, pigment plant (Savannah Plan). Most of the company's employees are eligible to participate in both the ESOP and the SIP or Savannah Plan. Although the ESOP, SIP and Savannah Plan are separate plans, matching contributions to the ESOP are contingent upon participants' contributions to the SIP or Savannah Plan. Effective December 31, 2004, the ESOP and the Savannah Plan were merged into the SIP.

In 1989, the ESOP trust borrowed $125 million from a group of lending institutions and used the proceeds to purchase approximately three million shares of the company's treasury stock. The company used the $125 million in proceeds from the sale of the stock to acquire shares of its common stock in open-market and privately negotiated transactions. In 1996, a portion of the third-party borrowings was replaced with a note payable to the company (sponsor financing), which was fully paid in 2003. The third-party borrowings are guaranteed by the company and are reflected in the Consolidated Balance Sheet as long-term debt due within one year (see Note 14).

In 1999, the company merged with Oryx Energy Company, which sponsored the Oryx Capital Accumulation Plan (CAP). CAP was a combined stock bonus and leveraged employee stock ownership plan available to substantially all U.S. employees of the former Oryx operations. During 1999, the company merged the Oryx CAP into the ESOP and SIP. In 1989, Oryx privately placed $110 million of notes pursuant to the provisions of the CAP. Oryx loaned the proceeds to the CAP, which used the funds to purchase Oryx common stock that was placed in a trust. Because this loan represents sponsor financing, it does not appear in the accompanying balance sheet. The remaining balance of the sponsor financing is $30 million at year-end 2004.

Shares of stock allocated to the ESOP participants' accounts and in the loan suspense account are as follows:

(Thousands of shares)	**2004**	2003
Participants' accounts	**1,432**	1,496
Loan suspense account	**246**	315

The shares in the loan suspense account at December 31, 2004, included approximately 17,000 released shares that were allocated to participants' accounts in January 2005. At December 31, 2003, the shares in the loan suspense account included approximately 5,000 released shares that were allocated to participants' accounts in January 2004.

Compensation expense related to the plan was $13 million, $33 million and $19 million in 2004, 2003 and 2002, respectively. These amounts include interest expense incurred on the third-party ESOP debt, which was not material for 2004, 2003 or 2002. The company contributed $17 million, $42 million and $27 million to the ESOP in 2004, 2003 and 2002, respectively. Included in the respective contributions were $10 million, $37 million and $19 million for principal and interest payments on the financings. The cash contributions are net of $3 million, $4 million and $5 million for the dividends paid on the company stock held by the ESOP trust in 2004, 2003 and 2002, respectively.

23. Taxes, Other than Income Taxes

Taxes, other than income taxes, as shown in the Consolidated Statement of Operations for the years ended December 31, 2004, 2003 and 2002, are comprised of the following:

(Millions of dollars)	**2004**	2003	2002
Production/severance	**$ 84**	$46	$ 58
Payroll	**28**	29	20
Property	**31**	18	19
Other	**5**	3	5
Total	**$148**	$96	$102

24. Other Income (Expense)

Other income (expense) included the following during each of the years in the three-year period ended December 31, 2004:

(Millions of dollars)	**2004**	2003	2002
Net foreign currency transaction loss	**$(21)**	$(41)	$(38)
Equity in net losses of equity method investees	**(26)**	(33)	(25)
Gain on sale of Devon stock	**9**	17	–
Derivatives and Devon stock revaluation [(1)]	**2**	4	35
Interest income	**6**	5	5
Loss on accounts receivables sales and other	**(10)**	(9)	(8)
Total	**$(40)**	$(57)	$(31)

[(1)] See Notes 7 and 11 for additional information related to accounting for Devon stock and DECS.

25. Asset Impairments, Asset Disposals and Discontinued Operations

Asset Impairments – In September 2004, the company shut down sulfate-process titanium dioxide pigment production at its Savannah, Georgia facility. In connection with the closure, the company recognized an $8 million asset impairment loss on indefinite-lived intangible assets in 2004. See Note 13 for information on other provisions related to the shutdown.

The chemical – pigment operating unit began production through a new high-productivity oxidation line at the Savannah, Georgia, chloride process pigment plant in January 2004. This new technology results in low-cost, incremental capacity increases through modification of existing chloride oxidation lines and allows for improved operating efficiencies through simplification of hardware configurations and reduced maintenance requirements. As of the end of the year, the company continued to operate its new high-productivity oxidation line and continued to evaluate its performance. The company expects to have a better understanding of how the Savannah site might be reconfigured to exploit its capabilities in 2005. The possible reconfiguration of the Savannah site, if any, could include redeployment of certain assets, idling of certain assets and reduction of the future useful life of certain assets, resulting in the acceleration of depreciation expense and the recognition of other charges.

Impairment losses on held-for-use assets totaled $28 million and $14 million in 2004 and 2003, respectively. The 2004 impairments related primarily to two U.S. Gulf of Mexico fields that experienced premature water breakthrough and ceased production sooner than expected ($17 million), as well as $8 million for a U.K. North Sea field that is no longer certain to be developed and $3 million associated with other minor onshore U.S. properties. The 2003 impairments related to mature oil and gas producing assets in the U.S. onshore and Gulf of Mexico shelf areas. Impairment losses totaling $646 million were recorded in 2002, including $541 million for the Leadon field in the U.K. North Sea, $82 million for certain other North Sea fields and $23 million for several older Gulf of Mexico shelf properties. Negative reserve revisions stemming from additional performance analysis for these properties during 2002 resulted in revised estimates of future cash flows from the properties that were less than the carrying values of the related assets. The chemical - pigment operating unit recorded a $12 million pretax write-down of property, plant and equipment in 2002 related to abandoned chemical engineering projects, which is reflected in depreciation and depletion in the Consolidated Statement of Operations.

The company continues to review its options with respect to its 100%-owned Leadon field and, particularly, the associated floating production, storage and offloading (FPSO) facility. Management presently intends to continue operating and producing the field until such time as the operating cash flow generated by the field does not support continued production or until a higher value option is identified. Given the significant value associated with the FPSO relative to the size of the entire project, the company will continue to pursue a long-term solution that achieves maximum value for Leadon – which may include disposing of the field, monetizing the FPSO by selling it as a development option for a third-party discovery, or redeployment in other company operations. As of December 31, 2004, the carrying value of the Leadon field assets totaled $336 million. Given the uncertainty concerning possible outcomes, it is at least reasonably possible that the company's estimate of future cash flows from the Leadon field and associated fair value could change in the near term due to, among other things, (i) unfavorable changes in commodity prices or operating costs, (ii) a production profile that declines more rapidly than anticipated, and/or (iii) failure to locate a strategic buyer or suitable redeployment opportunity for the FPSO. Accordingly, management anticipates that the Leadon field will be subject to periodic impairment review until such time as the field is abandoned or sold. If future cash flows or fair value decrease from that presently estimated, an additional write-down of the Leadon field could occur in the future.

Discontinued Operations – During 2002, the company approved a plan to exit its forest products business, which was part of the chemical - other operating unit. This decision was made as part of the company's strategic plan to focus on its core businesses. At the time of this decision, five plants were in operation. Four of these plants were closed and abandoned during 2003. Provisions associated with the closure of these plants are discussed in more detail in Note 13. The fifth plant, a leased facility, was operated throughout 2004 until the lease expired and the fixed assets at the facility were sold in January 2005. Criteria for classification of these assets as held for sale were met in the fourth quarter 2004, at which time the results of forest products operations met the requirements for reporting as discontinued operations in the accompanying Consolidated Statement of Operations for all years presented. The assets held for sale at December 31, 2004 are included in Long-Term Assets Associated with Properties Held for Disposal in the Consolidated Balance Sheet at estimated sales price less costs to sell of $3 million. No gain or loss was recognized on the disposition of these assets.

Revenues applicable to the discontinued operations totaled $22 million, $105 million and $131 million for 2004, 2003, and 2002, respectively. Pretax loss from discontinued operations totaled $17 million, $16 million and $32 million for the years 2004, 2003, and 2002, respectively.

During 2002, the company approved a plan to dispose of its exploration and production operations in Kazakhstan, its interest in the Bayu-Undan project in the East Timor Sea offshore Australia and its interest in the Jabung block of Sumatra, Indonesia. These divestiture decisions were made as part of the company's strategic plan to rationalize noncore oil and gas properties. The results of these operations have been reported separately as discontinued operations in the accompanying Consolidated Statement of Operations for all years presented. In conjunction with the disposals, the related assets were evaluated and losses were recorded for the Kazakhstan operations, calculated as the difference between the estimated sales price for the operation, less costs to sell, and the operations' carrying value. The losses totaled $6 million in 2003 and $35 million in 2002 and are reported as part of discontinued operations. On March 31, 2003, the company completed the sale of its Kazakhstan operations for $169 million. In 2002, the company completed the sale of its interest in the Bayu-Undan project for $132 million in cash, resulting in a pretax gain of $35 million. The company also completed the sale of its Sumatra operations in 2002 for $171 million in cash with an $11 million contingent purchase price pending government approval of an LPG project. The sale resulted in a pretax gain of $72 million (excluding the contingent purchase price). The net proceeds received by the company from these sales were used to reduce outstanding debt.

Revenues applicable to the discontinued operations totaled $6 million and $36 million for 2003 and 2002, respectively. Pretax income for the discontinued operations totaled nil (including the loss on sale of $6 million) and $104 million (including the gains on sale of $107 million and the loss on sale of $35 million) for the years 2003 and 2002, respectively.

Asset Disposals – The company recognized a net loss on sale of assets of $29 million in 2004. The loss was associated primarily with the conveyance of the company's interest in a nonproducing Gulf of Mexico field to another participating partner ($25 million), as well as losses of $6 million and gains of $2 million on sales of noncore properties in the Gulf of Mexico shelf and U.S. onshore areas. At December 31, 2004, the company had oil and gas properties with a carrying amount of $5 million classified as held for sale.

In connection with the company's divestiture program initiated in 2002, certain oil and gas properties were identified for disposal and classified as held-for-sale properties. Losses of $23 million and gains of $68 million were recognized in 2003 upon conclusion of the divestiture program in the U.S. and North Sea, and for the sale of the company's interest in the South China Sea (Liuhua field) and other noncore U.S. properties (onshore and Gulf of Mexico shelf areas). The company recognized losses of $176 million in 2002 associated with oil and gas properties held for sale in the U.S. (onshore and Gulf of Mexico shelf areas), the U.K. North Sea and Ecuador. Proceeds realized from these disposals totaled $119 million in 2003 and $374 million in 2002. The proceeds from the sale of these properties were used to reduce long-term debt.

26. Earnings Per Share

Basic earnings per share includes no dilution and is computed by dividing income or loss from continuing operations available to common stockholders by the weighted-average number of common shares outstanding for the period. Diluted earnings per share reflects the potential dilution that could occur if security interests were exercised or converted into common stock.

The following table sets forth the computation of basic and diluted earnings per share from continuing operations for the years ended December 31, 2004, 2003 and 2002:

	2004			2003			2002		
(Millions of dollars, except per-share amounts, and thousands of shares)	Income from Continuing Operations	Shares	Per-share Income	Income from Continuing Operations	Shares	Per-share Income	Loss from Continuing Operations	Shares	Per-share Loss
Basic earnings per share	**$415**	**126,313**	**$3.29**	$264	100,145	$2.63	$(590)	100,330	$(5.89)
Effect of dilutive securities:									
5.25% convertible debentures	**21**	**9,824**		21	9,824		–	–	
Restricted stock	–	**449**		–	697		–	–	
Employee stock options	–	**333**		–	17		–	–	
Diluted earnings per share	**$436**	**136,919**	**$3.19**	$285	110,683	$2.58	$(590)	100,330	$(5.89)

The weighted average of diluted shares outstanding during 2004 and 2003 did not include the effect of employee stock options that were antidilutive because they were not "in the money" during the respective years. At December 31, 2004 and 2003 there were 2,981,936 and 4,866,144 of such options outstanding, with weighted average exercise prices of $63.63 and $60.26, respectively. Because the company incurred a loss from continuing operations for 2002, all of the potentially issuable common shares were antidilutive, including 5,018,856 of shares potentially issuable upon exercise of the employee stock options and 9,823,778 shares issuable upon conversion of the 5.25% Convertible Subordinated Debentures.

As discussed in Note 35, in March 2005 all of the 5.25% debentures were converted by the holders into 9.8 million shares of common stock.

27. Reporting by Business Segments and Geographic Locations

The company has three reportable segments: oil and gas exploration and production, production and marketing of titanium dioxide pigment, and production and marketing of other chemical products. The exploration and production unit explores for, develops, produces and markets crude oil and natural gas, with major areas of operation in the United States, the United Kingdom sector of the North Sea and China. Exploration efforts also extend to Australia, Benin, Bahamas, Brazil, Morocco, Canada, and the Danish and Norwegian sectors of the North Sea. The chemical unit primarily produces and markets titanium dioxide pigment and has production facilities in the United States, Australia, Germany and the Netherlands. Other chemical products segment represents the company's electrolytic manufacturing and marketing operations. All operations of the chemical - other segment are located in the United States. Segment performance is evaluated based on operating profit (loss), which represents results of operations before considering general corporate expenses, interest and debt expense, environmental provisions related to businesses in which the company's affiliates are no longer engaged, other income (expense) and income taxes.

Crude oil sales to individually significant customers totaled $499 million to BP PLC and subsidiaries (BP) in 2004; $446 million to BP in 2003; and $408 million to Texon L.P. and $450 million to BP in 2002. In addition, natural gas sales totaled $183 million to BP and $952 million to Cinergy Marketing & Trading LP (Cinergy) in 2004; $103 million to BP and $782 million to Cinergy in 2003; and $72 million to BP and $496 million to Cinergy in 2002. Sales to subsidiary companies are eliminated as described in Note 1.

(Millions of dollars)	**2004**	2003	2002
Revenues –			
Exploration and production	**$3,855**	$2,923	$2,450
Chemical –			
Pigment	**1,209**	1,079	995
Other	**93**	78	70
Total Chemical	**1,302**	1,157	1,065
Total	**$5,157**	$4,080	$3,515
Operating profit (loss) –			
Exploration and production	**$1,249**	$1,002	$ (140)
Chemical –			
Pigment	**(80)**	(13)	24
Other	**(1)**	(23)	(13)
Total Chemical	**(81)**	(36)	11
Total	**1,168**	966	(129)
Interest and debt expense	**(245)**	(251)	(275)
Corporate expenses	**(130)**	(152)	(158)
Provision for environmental remediation and restoration, net of reimbursements (1)	**(82)**	(47)	(32)
Other income (expense) (2)	**(40)**	(57)	(31)
Benefit (provision) for income taxes	**(256)**	(195)	35
Discontinued operations, net of taxes	**(11)**	(10)	105
Cumulative effect of change in accounting principle, net of taxes	**–**	(35)	–
Net income (loss)	**$ 404**	$ 219	$ (485)
Depreciation, depletion and amortization –			
Exploration and production (3)	**$ 917**	$ 678	$ 758
Chemical –			
Pigment	**182**	110	97
Other	**14**	15	15
Total Chemical	**196**	125	112
Other	**10**	8	6
Discontinued operations	**1**	3	8
Total	**$1,124**	$ 814	$ 884

(1) Includes provisions, net of reimbursements, related to various businesses in which the company's affiliates are no longer engaged; for example, the refining and marketing of oil and gas and associated petroleum products, and the mining and processing of uranium and thorium. See Note 19.

(2) The company owns a 50% interest in Avestor, a joint venture involved in production of lithium-metal-polymer batteries. Investment in Avestor is accounted for under the equity method. The company's equity in the net losses of Avestor amounts to $39 million, $28 million and $24 million in 2004, 2003 and 2002, respectively. The carrying value of the company's investment in Avestor at December 31, 2004 and 2003 was $60 million and $74 million, respectively.

(3) Includes amortization of nonproducing leasehold costs that is reported in exploration expense in the Consolidated Statement of Operations.

(Millions of dollars)	**2004**	2003	2002
Capital expenditures –			
Exploration and production			
(excludes Gunnison lease of $83 in 2003)	**$ 1,152**	$ 869	$ 988
Chemical –			
Pigment	**83**	90	78
Other	**9**	7	7
Total Chemical	**92**	97	85
Other	**18**	15	58
Discontinued operations	**–**	–	28
Total	**1,262**	981	1,159
Exploration expense –			
Exploration and production –			
Dry hole expense	**161**	181	113
Amortization of undeveloped leases	**63**	69	67
Other	**132**	104	93
Total	**356**	354	273
Total capital expenditures and exploration expense	**$ 1,618**	$ 1,335	$1,432
Total assets –			
Exploration and production	**$12,246**	$ 7,385	$7,030
Chemical –			
Pigment	**1,359**	1,521	1,413
Other	**184**	213	242
Total Chemical	**1,543**	1,734	1,655
Total	**13,789**	9,119	8,685
Corporate and other assets	**726**	1,127	1,038
Discontinued operations	**3**	4	186
Total	**$14,518**	$10,250	$9,909
Revenues –			
U.S. operations	**$ 3,720**	$ 2,755	$2,059
International operations –			
North Sea – exploration and production	**759**	791	936
China – exploration and production	**92**	23	30
Other – exploration and production	**–**	–	28
Europe – pigment	**361**	313	294
Australia – pigment	**225**	198	168
	1,437	1,325	1,456
Total	**$ 5,157**	$ 4,080	$3,515
Operating profit (loss) –			
U.S. operations	**$ 880**	$ 634	$ 332
International operations –			
North Sea – exploration and production	**277**	353	(412)
China – exploration and production	**41**	1	7
Other – exploration and production	**(52)**	(66)	(59)
Europe – pigment	**(16)**	14	(21)
Australia – pigment	**38**	30	24
	288	332	(461)
Total	**$ 1,168**	$ 966	$ (129)
Net property, plant and equipment –			
U.S. operations	**$ 8,425**	$ 4,973	$4,590
International operations –			
North Sea – exploration and production	**1,754**	1,874	1,912
China – exploration and production	**226**	165	115
Other – exploration and production	**26**	4	13
Europe – pigment	**303**	281	238
Australia – pigment	**93**	102	110
	2,402	2,426	2,388
Total	**$10,827**	$ 7,399	$6,978

28. **Condensed Consolidating Financial Information**

On October 3, 2001, Kerr-McGee Corporation issued $1.5 billion of long-term notes in a public offering. On July 1, 2004, Kerr-McGee Corporation issued an additional $650 million of long-term notes. The notes are general, unsecured obligations of the company and rank in parity with all of the company's other unsecured and unsubordinated indebtedness. The notes have been fully and unconditionally guaranteed, on a joint and several basis, by Kerr-McGee Chemical Worldwide LLC and Kerr-McGee Rocky Mountain Corporation. Additionally, Kerr-McGee Corporation has guaranteed all indebtedness of its subsidiaries. As a result of these guarantee arrangements, the company is required to present condensed consolidating financial information.

The following tables present condensed consolidating financial information for (a) Kerr-McGee Corporation, the parent company, (b) the guarantor subsidiaries, and (c) the nonguarantor subsidiaries on a consolidated basis. The guarantor subsidiaries include Kerr-McGee Chemical Worldwide LLC and Kerr-McGee Rocky Mountain Corporation, wholly-owned subsidiaries of Kerr-McGee Corporation. Other income (expense) in the Condensed Consolidating Statement of Operations includes equity interest in income (loss) of subsidiaries for all periods presented.

Condensed Consolidating Statement of Operations for the Year Ended December 31, 2004

(Millions of dollars)	Kerr-McGee Corporation	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$ –	$ 864	$4,293	$ –	$5,157
Costs and Expenses					
Costs and operating expenses	–	519	1,436	(2)	1,953
Selling, general and administrative expenses	1	7	329	–	337
Shipping and handling expenses	–	8	158	–	166
Depreciation and depletion	–	120	940	–	1,060
Accretion expense	–	3	27	–	30
Asset impairments	–	3	33	–	36
Loss associated with assets held for sale	–	–	29	–	29
Exploration, including exploratory dry holes and amortization of undeveloped leases	–	14	342	–	356
Taxes, other than income taxes	–	38	110	–	148
Provision for environmental remediation and restoration, net of reimbursements	–	66	20	–	86
Interest and debt expense	138	36	304	(233)	245
Total Costs and Expenses	139	814	3,728	(235)	4,446
	(139)	50	565	235	711
Other Income (Expense)	793	(117)	108	(824)	(40)
Income (Loss) before Income Taxes	654	(67)	673	(589)	671
Benefit (Provision) for Income Taxes	(250)	24	(259)	229	(256)
Income from Continuing Operations	404	(43)	414	(360)	415
Income (Loss) from Discontinued Operations, net of taxes	–	–	(11)	–	(11)
Net Income (Loss)	$404	$ (43)	$ 403	$(360)	$ 404

Condensed Consolidating Statement of Operations for the Year Ended December 31, 2003

(Millions of dollars)	Kerr-McGee Corporation	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$ –	$694	$3,386	$ –	$4,080
Costs and Expenses					
Costs and operating expenses	–	351	1,214	(2)	1,563
Selling, general and administrative expenses	–	14	351	–	365
Shipping and handling expenses	–	9	130	–	139
Depreciation and depletion	–	122	620	–	742
Accretion expense	–	2	23	–	25
Asset impairments	–	–	14	–	14
Loss (gain) associated with assets held for sale	–	1	(46)	–	(45)
Exploration, including exploratory dry holes and amortization of undeveloped leases	–	15	339	–	354
Taxes, other than income taxes	–	25	71	–	96
Provision for environmental remediation and restoration, net of reimbursements	–	31	29	–	60
Interest and debt expense	116	36	277	(178)	251
Total Costs and Expenses	116	606	3,022	(180)	3,564
	(116)	88	364	180	516
Other Income (Expense)	506	(9)	67	(621)	(57)
Income (Loss) from Continuing Operations before Income Taxes	390	79	431	(441)	459
Benefit (Provision) for Income Taxes	(189)	23	(177)	148	(195)
Income (Loss) from Continuing Operations	201	102	254	(293)	264
Income (Loss) from Discontinued Operations, net of taxes	–	12	(20)	(2)	(10)
Cumulative Effect of Change in Accounting Principle, net of taxes	–	(1)	(34)	–	(35)
Net Income (Loss)	$ 201	$113	$ 200	$(295)	$ 219

Condensed Consolidating Statement of Operations for the Year Ended December 31, 2002

(Millions of dollars)	Kerr-McGee Corporation	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$ –	$351	$3,423	$(259)	$3,515
Costs and Expenses					
Costs and operating expenses	–	105	1,498	(260)	1,343
Selling, general and administrative expenses	–	4	304	–	308
Shipping and handling expenses	–	9	115	–	124
Depreciation and depletion	–	121	688	–	809
Asset impairments	–	3	643	–	646
Loss associated with assets held for sale	–	–	176	–	176
Exploration, including exploratory dry holes and amortization of undeveloped leases	–	12	261	–	273
Taxes, other than income taxes	–	16	86	–	102
Provision for environmental remediation and restoration, net of reimbursements	–	–	53	–	53
Interest and debt expense	115	36	323	(199)	275
Total Costs and Expenses	115	306	4,147	(459)	4,109
	(115)	45	(724)	200	(594)
Other Income (Expense)	(438)	484	(123)	46	(31)
Income (Loss) from Continuing Operations before Income Taxes	(553)	529	(847)	246	(625)
Benefit (Provision) for Income Taxes	68	(26)	33	(40)	35
Income (Loss) from Continuing Operations	(485)	503	(814)	206	(590)
Income from Discontinued Operations, net of taxes	–	–	105	–	105
Net Income (Loss)	$(485)	$503	$ (709)	$ 206	$ (485)

Condensed Consolidating Balance Sheet as of December 31, 2004

(Millions of dollars)	Kerr-McGee Corporation	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Current Assets					
Cash and cash equivalents	$ 2	$ –	$ 74	$ –	$ 76
Intercompany receivables	–	–	58	(58)	–
Accounts receivable	–	206	757	–	963
Inventories	–	5	324	–	329
Derivatives and other assets	4	24	167	–	195
Deferred income taxes	2	13	309	–	324
Total Current Assets	8	248	1,689	(58)	1,887
Property, Plant and Equipment – Net	–	1,947	8,880	–	10,827
Investments in Subsidiaries	6,306	645	–	(6,951)	–
Investments, Derivatives and Other Assets	17	24	547	(80)	508
Goodwill	–	346	851	–	1,197
Other Intangible Assets	–	5	86	–	91
Long-Term Assets Associated with Properties Held for Disposal	–	–	8	–	8
Total Assets	$6,331	$3,215	$12,061	$(7,089)	$14,518
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Intercompany borrowings	$ 68	$ 598	$ 1,189	$(1,855)	$ –
Accounts payable	68	55	521	–	644
Long-term debt due within one year	354	–	109	–	463
Derivative liabilities	6	71	295	–	372
Accrued liabilities	10	203	813	–	1,026
Total Current Liabilities	506	927	2,927	(1,855)	2,505
Long-Term Debt	2,125	–	1,111	–	3,236
Noncurrent Liabilities					
Deferred income taxes	(2)	545	1,634	–	2,177
Derivative liabilities	–	59	149	–	208
Other noncurrent liabilities	–	224	853	(3)	1,074
Total Noncurrent Liabilities	(2)	828	2,636	(3)	3,459
Stockholders' Equity	3,702	1,460	5,387	(5,231)	5,318
Total Liabilities and Stockholders' Equity	$6,331	$3,215	$12,061	$(7,089)	$14,518

Condensed Consolidating Balance Sheet as of December 31, 2003

(Millions of dollars)	Kerr-McGee Corporation	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Current Assets					
Cash and cash equivalents	$ 2	$ –	$ 140	$ –	$ 142
Intercompany receivables	7	–	59	(66)	–
Accounts receivable	–	125	458	–	583
Inventories	–	6	388	–	394
Investment in equity securities	–	–	510	–	510
Derivatives and other assets	–	18	109	–	127
Deferred income taxes	1	18	57	–	76
Current assets associated with properties held for disposal	–	–	1	–	1
Total Current Assets	10	167	1,722	(66)	1,833
Property, Plant and Equipment – Net	–	1,967	5,432	–	7,399
Investments in Subsidiaries	3,182	732	–	(3,914)	–
Investments, Derivatives and Other Assets	10	96	539	(80)	565
Goodwill	–	346	11	–	357
Other Intangible Assets	–	9	55	–	64
Long-Term Assets Associated with Properties Held for Disposal	–	–	32	–	32
Total Assets	$3,202	$3,317	$7,791	$(4,060)	$10,250
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Intercompany borrowings	$ 69	$ 893	$1,089	$(2,051)	$ –
Accounts payable	45	39	391	–	475
Long-term debt due within one year	–	–	574	–	574
Derivative liabilities	4	7	343	–	354
Accrued liabilities	33	167	629	–	829
Total Current Liabilities	151	1,106	3,026	(2,051)	2,232
Long-Term Debt	1,829	–	1,252	–	3,081
Noncurrent Liabilities					
Deferred income taxes	(5)	483	857	–	1,335
Derivative liabilities	–	2	–	–	2
Other noncurrent liabilities	–	211	739	(2)	948
Total Noncurrent Liabilities	(5)	696	1,596	(2)	2,285
Long-Term Liabilities Associated with Properties Held for Disposal	–	–	16	–	16
Stockholders' Equity	1,227	1,515	1,901	(2,007)	2,636
Total Liabilities and Stockholders' Equity	$3,202	$3,317	$7,791	$(4,060)	$10,250

Condensed Consolidating Statement of Cash Flows for the Year Ended December 31, 2004

(Millions of dollars)	Kerr-McGee Corporation	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash Flow from Operating Activities					
Net income (loss)	$ 404	$ (43)	$ 403	$(360)	$ 404
Adjustments to reconcile net income (loss) to net cash provided by operating activities –					
Depreciation, depletion and amortization	–	125	999	–	1,124
Deferred income taxes	2	(4)	110	–	108
Dry hole expense	–	2	159	–	161
Asset impairments	–	3	33	–	36
(Gain) loss on assets held for sale and asset disposal	–	(1)	21	–	20
Accretion expense	–	3	27	–	30
Provision for environmental remediation and restoration, net of reimbursements	–	66	26	–	92
Equity in losses (earnings) of subsidiaries	(439)	77	–	362	–
Other noncash items affecting net income (loss)	2	114	44	–	160
Other net cash provided by (used in) operating activities	(19)	4	(68)	(2)	(85)
Net cash provided by (used in) operating activities	(50)	346	1,754	–	2,050
Cash Flow from Investing Activities					
Capital expenditures	–	(108)	(1,154)	–	(1,262)
Dry hole costs	–	(2)	(76)	–	(78)
Acquisitions, net of cash acquired	–	–	43	–	43
Proceeds from sales of assets	–	7	16	–	23
Other investing activities	–	–	12	–	12
Net cash used in investing activities	–	(103)	(1,159)	–	(1,262)
Cash Flow from Financing Activities					
Issuance of long-term debt	636	–	41	–	677
Issuance of common stock	56	–	–	–	56
Repayment of debt	–	–	(1,278)	–	(1,278)
Increase (decrease) in intercompany notes payable	(437)	(243)	680	–	–
Dividends paid	(205)	–	–	–	(205)
Settlement of Westport derivatives	–	–	(101)	–	(101)
Net cash provided by (used in) financing activities	50	(243)	(658)	–	(851)
Effects of Exchange Rate Changes on Cash and Cash Equivalents	–	–	(3)	–	(3)
Net Decrease in Cash and Cash Equivalents	–	–	(66)	–	(66)
Cash and Cash Equivalents at Beginning of Year	2	–	140	–	142
Cash and Cash Equivalents at End of Year	$ 2	$ –	$ 74	$ –	$ 76

Condensed Consolidating Statement of Cash Flows for the Year Ended December 31, 2003

(Millions of dollars)	Kerr-McGee Corporation	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash Flow from Operating Activities					
Net income (loss)	$ 201	$ 113	$ 200	$(295)	$ 219
Adjustments to reconcile net income (loss) to net cash provided by operating activities –					
Depreciation, depletion and amortization	–	127	687	–	814
Deferred income taxes	(6)	(8)	170	–	156
Dry hole expense	–	–	181	–	181
Asset impairments	–	–	14	–	14
Gain on assets held for sale and asset disposal	–	(12)	(28)	–	(40)
Accretion expense	–	2	23	–	25
Cumulative effect of change in accounting principle	–	1	34	–	35
Provision for environmental remediation and restoration, net of reimbursements	–	31	31	–	62
Equity in losses (earnings) of subsidiaries	(227)	65	–	162	–
Other noncash items affecting net income (loss)	1	15	78	–	94
Other net cash provided by (used in) operating activities	3	(138)	93	–	(42)
Net cash provided by (used in) operating activities	(28)	196	1,483	(133)	1,518
Cash Flow from Investing Activities					
Capital expenditures	–	(129)	(852)	–	(981)
Dry hole costs	–	–	(181)	–	(181)
Acquisitions, net of cash acquired	–	–	(110)	–	(110)
Proceeds from sales of assets	–	8	296	–	304
Other investing activities	–	–	17	–	17
Net cash used in investing activities	–	(121)	(830)	–	(951)
Cash Flow from Financing Activities					
Issuance of long-term debt	–	–	31	–	31
Repayment of debt	(18)	–	(351)	–	(369)
Increase (decrease) in intercompany notes payable	226	(75)	(152)	1	–
Dividends paid	(181)	–	(134)	134	(181)
Other financing activities	–	–	1	(2)	(1)
Net cash provided by (used in) financing activities	27	(75)	(605)	133	(520)
Effects of Exchange Rate Changes on Cash and Cash Equivalents	–	–	5	–	5
Net Increase (Decrease) in Cash and Cash Equivalents	(1)	–	53	–	52
Cash and Cash Equivalents at Beginning of Year	3	–	87	–	90
Cash and Cash Equivalents at End of Year	$ 2	$ –	$ 140	$ –	$ 142

Condensed Consolidating Statement of Cash Flows for the Year Ended December 31, 2002

(Millions of dollars)	Kerr-McGee Corporation	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash Flow from Operating Activities					
Net income (loss)	$(485)	$ 503	$ (709)	$206	$ (485)
Adjustments to reconcile net income (loss) to net cash provided by operating activities –					
Depreciation, depletion and amortization	–	124	760	–	884
Deferred income taxes	–	9	(121)	–	(112)
Dry hole expense	–	–	113	–	113
Asset impairments	–	3	649	–	652
Loss on assets held for sale and asset disposal	–	–	100	–	100
Provision for environmental remediation and restoration, net of reimbursements	–	–	89	–	89
Equity in losses (earnings) of subsidiaries	465	(25)	–	(440)	–
Other noncash items affecting net income (loss)	–	(26)	102	–	76
Other net cash provided by (used in) operating activities	(16)	341	(194)	–	131
Net cash provided by (used in) operating activities	(36)	929	789	(234)	1,448
Cash Flow from Investing Activities					
Capital expenditures	–	(179)	(980)	–	(1,159)
Dry hole costs	–	–	(113)	–	(113)
Acquisitions, net of cash acquired	–	–	(24)	–	(24)
Proceeds from sales of assets	–	61	695	–	756
Other investing activities	–	(700)	647	–	(53)
Net cash provided by (used in) investing activities	–	(818)	225	–	(593)
Cash Flow from Financing Activities					
Issuance of long-term debt	350	–	68	–	418
Issuance of common stock	5	–	–	–	5
Repayment of debt	–	–	(1,101)	–	(1,101)
Increase (decrease) in intercompany notes payable	(135)	(112)	248	(1)	–
Dividends paid	(181)	–	(235)	235	(181)
Net cash provided by (used in) financing activities	39	(112)	(1,020)	234	(859)
Effects of Exchange Rate Changes on Cash and Cash Equivalents	–	–	3	–	3
Net Increase (Decrease) in Cash and Cash Equivalents	3	(1)	(3)	–	(1)
Cash and Cash Equivalents at Beginning of Year	–	1	90	–	91
Cash and Cash Equivalents at End of Year	$ 3	$ –	$ 87	$ –	$ 90

29. **Costs Incurred in Crude Oil and Natural Gas Activities**

Total expenditures, both capitalized and expensed, for crude oil and natural gas property acquisition, exploration and development activities for the three years ended December 31, 2004, are reflected in the following table:

(Millions of dollars)	Property Acquisition Costs(1)	Exploration Costs(2)	Development Costs(3)	Total
2004 –				
United States	$3,405	$231	$746	$4,382
North Sea	4	36	107	147
China	1	19	75	95
Other international	25	51	–	76
Total finding, development and acquisition costs incurred	3,435	337	928	4,700
Asset retirement costs (4)	72	–	14	86
Total costs incurred	$3,507	$337	$942	$4,786
2003 –				
United States	$ 121	$357	$473	$ 951
North Sea	46	43	55	144
China	1	31	45	77
Other international	1	49	–	50
Total finding, development and acquisition costs incurred	169	480	573	1,222
Asset retirement costs (4)	9	–	2	11
Total costs incurred	$ 178	$480	$575	$1,233
2002 –				
United States	$ 89	$206	$426	$ 721
North Sea	55	14	296	365
China	–	14	16	30
Other international	2	44	–	46
Total continuing operations	146	278	738	1,162
Discontinued operations	2	1	5	8
Total costs incurred	$ 148	$279	$743	$1,170

(1) Includes $2.374 billion, $103 million and $69 million applicable to purchases of proved reserves in place in 2004, 2003 and 2002, respectively.

(2) Exploration costs include delay rentals, exploratory dry holes, dry hole and bottom hole contributions, geological and geophysical costs, costs of carrying and retaining properties, and capital expenditures, such as costs of drilling and equipping successful exploratory wells.

(3) Development costs include costs incurred to obtain access to proved reserves (surveying, clearing ground, building roads), to drill and equip development wells, and to acquire, construct and install production facilities and improved-recovery systems. Development costs also include costs of developmental dry holes.

(4) Asset retirement costs represent the noncash increase in property, plant and equipment recognized when initially recording a liability for abandonment obligations (discounted) associated with the company's oil and gas wells and platforms. Asset retirement costs are depleted on a unit-of-production basis over the useful life of the related field. See further discussion in Note 16 regarding the 2003 adoption of FAS No. 143.

30. Results of Operations from Crude Oil and Natural Gas Activities

The results of operations from crude oil and natural gas activities for the three years ended December 31, 2004, consist of the following:

(Millions of dollars)	Revenues	Production (Lifting) Costs	Other Costs	Exploration Expenses	Depreciation, Depletion and Accretion	Loss (Gain) on Held for Sale Properties and Asset Impairments	Income Tax Expense (Benefit)	Results of Operations, Producing Activities
2004 –								
United States	$2,520	$385	$188	$265	$620	$ 50	$355	$ 657
North Sea	741	158	53	32	229	8	116	145
China	92	13	5	11	22	(1)	14	28
Other international	–	–	6	48	1	–	(19)	(36)
Total crude oil and natural gas activities	3,353	556	252 (1)	356	872	57	466	794
Other (2)	502	–	501	–	12	–	(3)	(8)
Total	$3,855	$556	$753	$356	$884	$ 57	$463	$ 786
2003 –								
United States	$1,775	$235	$149	$249	$400	$ (4)	$255	$ 491
North Sea	783	146	60	27	220	(15)	147	198
China	23	5	8	19	2	(12)	1	–
Other international	–	–	6	59	1	–	(22)	(44)
Total crude oil and natural gas activities	2,581	386	223 (1)	354	623	(31)	381	645
Other (2)	342	–	355	–	11	–	(8)	(16)
Total from continuing operations	2,923	386	578	354	634	(31)	373	629
Discontinued operations	6	1	2	–	–	6	–	(3)
Total	$2,929	$387	$580	$354	$634	$ (25)	$373	$ 626
2002 –								
United States	$1,367	$254	$106	$159	$389	$111	$116	$ 232
North Sea	920	244	60	48	288	706	33	(459)
China	30	10	5	5	3	–	2	5
Other international	29	7	14	61	–	5	(17)	(41)
Total crude oil and natural gas activities	2,346	515	185 (1)	273	680	822	134	(263)
Other (2)	104	–	105	–	10	–	(4)	(7)
Total from continuing operations	2,450	515	290	273	690	822	130	(270)
Discontinued operations	36	4	14	1	3	35	–	(21)
Total	$2,486	$519	$304	$274	$693	$857	$130	$(291)

(1) Includes transportation, general and administrative expense, and taxes other than income taxes associated with oil and gas producing activities.

(2) Includes gas marketing activities, gas processing plants, pipelines and other items that do not fit the definition of crude oil and natural gas producing activities but have been included above to reconcile to the segment presentations.

The table below presents the company's average per-unit sales price of crude oil and natural gas and lifting costs (lease operating expense and production and ad valorem taxes) per barrel of oil equivalent from continuing operations for each of the three years in the period ended December 31, 2004. Natural gas production has been converted to a barrel of oil equivalent based on approximate relative heating value (6 Mcf equals 1 barrel).

	2004	2003	2002
Average realized price of crude oil sold (per barrel) (1) –			
United States	**$29.11**	$26.14	$21.56
North Sea	**26.50**	25.82	22.41
China	**32.37**	29.66	24.84
Other international	**–**	–	20.28
Average	**28.23**	26.04	22.04
Average realized price of natural gas sold (per Mcf) (1) –			
United States	**$ 5.24**	$ 4.56	$ 3.04
North Sea	**4.06**	3.09	2.35
Average	**5.13**	4.37	2.95
Lifting costs (per barrel of oil equivalent) –			
United States	**$ 4.63**	$ 3.57	$ 3.64
North Sea	**5.56**	4.52	5.64
China	**4.37**	6.02	8.08
Other international	**–**	–	5.05
Average	**4.86**	3.90	4.45

(1) Includes the results of the company's hedging program, which reduced the average price of crude oil sold by \$8.53, \$2.46 and \$1.13 per barrel and natural gas sold by \$.75, \$.55 and \$.01 per Mcf in 2004, 2003 and 2002, respectively.

31. Capitalized Costs Related to Crude Oil and Natural Gas Activities

Capitalized costs related to crude oil and natural gas activities and the related reserves for depreciation, depletion and amortization at the end of 2004 and 2003 are set forth in the table below.

(Millions of dollars)	**2004**	2003 (1)
Capitalized costs –		
Proved properties	**$14,538**	$10,875
Unproved properties	**1,753**	837
Other	**439**	356
Total	**16,730**	12,068
Assets held for disposal	**6**	467
Total	**16,736**	12,535
Reserves for depreciation, depletion and amortization –		
Proved properties	**6,524**	5,403
Unproved properties	**222**	206
Other	**120**	100
Total	**6,866**	5,709
Assets held for disposal	**1**	439
Total	**6,867**	6,148
Net capitalized costs	**$ 9,869**	$ 6,387

(1) Certain prior year balances were reclassified to intangible assets. See Note 10.

Exploratory Drilling Costs

Under the successful efforts method of accounting, the costs of drilling an exploratory well are capitalized pending determination of whether proved reserves can be attributed to the discovery. In the case of onshore wells and offshore wells in relatively shallow water, that determination usually can be made upon or shortly after cessation of exploratory drilling operations. However, such determination may take longer in other areas (specifically, deepwater exploration and international locations) depending upon, among other things, (i) the amount of hydrocarbons discovered, (ii) the outcome of planned geological and engineering studies, (iii) the need for additional appraisal drilling to determine whether the discovery is sufficient to support an economic development plan and (iv) the requirement for government sanctioning in certain international locations before proceeding with development activities. As a consequence, the company has capitalized costs associated with exploratory wells on its Consolidated Balance Sheet at any point in time that may be charged to earnings in a future period if management determines that commercial quantities of hydrocarbons have not been discovered.

Initial and Ongoing Assessment of Deferred Exploratory Drilling Costs – When initial drilling operations are complete, management determines whether the well has discovered oil and gas reserves and, if so, whether those reserves can be classified as proved. Often, the determination of whether proved reserves can be recorded under strict Securities and Exchange Commission (SEC) guidelines cannot be made when drilling is completed. In those situations where management believes that commercial hydrocarbons have not been discovered, the exploratory drilling costs are reflected in the Consolidated Statement of Operations as dry hole costs (a component of exploration expense). Where sufficient hydrocarbons have been discovered to justify further exploration and/or appraisal activities, exploratory drilling costs are deferred on the Consolidated Balance Sheet pending the outcome of those activities.

At the end of each quarter, operating and financial management review the status of all deferred exploratory drilling costs in light of ongoing exploration activities – in particular, whether the company is making sufficient progress in its ongoing exploration and appraisal efforts or, in the case of discoveries requiring government sanctioning, whether development negotiations are under way and proceeding as planned. If management determines that future appraisal drilling or development activities are not likely to occur in the future, any associated exploratory well costs are expensed in that period.

Financial Statement Balances – The following table presents the amount of capitalized exploratory drilling costs at December 31 for each of the last three years, and changes in those amounts during the years then ended:

(Millions of dollars)	**2004**	2003	2002
Balance, January 1	**$143**	$117	$124
Additions, pending determination of proved reserves	**81**	71	49
Reclassification to proved oil and gas properties	**(20)**	(39)	(1)
Capitalized exploratory well costs charged to expense	**(68)**	(6)	(24)
Sales and conveyances	**–**	–	(31)
Balance, December 31	**$136**	$143	$117

At December 31, 2004, the company had capitalized costs of approximately $136 million associated with ongoing exploration and/or appraisal activities, primarily in the deepwater Gulf of Mexico, China, Alaska and Brazil. The following table presents the total amount of exploratory drilling costs at year-end 2004 by geographic area, including the length of time such costs have been carried on the Consolidated Balance Sheet:

		Costs Incurred			
(Millions of dollars)	Total	**2004**	2003	2002	Prior to 2002
Gulf of Mexico	$ 59	**$32**	$27	$ –	$ –
China	36	**9**	7	1	19
Alaska	20	**20**	–	–	–
Brazil	10	**10**	–	–	–
North Sea	6	**5**	1	–	–
Other	5	**5**	–	–	–
Total capitalized exploratory drilling costs	$136	**$81**	$35	$ 1	$19

Analysis of Exploratory Costs at December 31, 2004 – The vast majority of exploratory drilling costs deferred at year-end are associated with wells that are either (i) drilling at December 31, (ii) in an area requiring a major capital expenditure or additional appraisal activities before recording proved reserves such as the deepwater Gulf of Mexico, Alaska, Brazil and China, or (iii) subject to government review and approval of our development plans. The company has no deferred drilling costs associated with areas that require gas sales contracts or project financing in order to proceed with development plans. The following discussion describes major projects shown in the table above with costs deferred beyond one year from the balance sheet date.

China – Costs incurred in China prior to 2004 are associated with 13 successful exploratory wells in the CFD 11-6/12-1 area on Blocks 04/36 and 05/36 in Bohai Bay. Such costs have been deferred pending government approval of a sanctioned development plan. The formal development plan for the CFD 11-6/12-1 area is currently in the process of final approval by China National Offshore Oil Corporation (CNOOC) and the Chinese government. The company believes approval will be received in 2005, at which time the assessment of proved reserves for this area also is expected to be completed.

Deepwater Gulf of Mexico – Costs incurred in the deepwater Gulf of Mexico prior to 2004 relate to two exploration wells that are located in areas that require a major capital expenditure and/or additional appraisal activities before the determination of proved reserves can be made. In the case of the first well ($25 million), the drilling rig was released in October 2003 after successfully encountering hydrocarbons. The company is actively planning appraisal drilling at this time. Management expects that appraisal drilling will occur during 2005; however, if management determines during the year that future appraisal drilling is not likely to occur, all capitalized costs may be charged to exploration expense. In the case of the second well ($2 million), additional appraisal drilling activities occurred during 2004 and development planning is currently under way.

32. ***Crude Oil, Condensate, Natural Gas Liquids and Natural Gas Net Reserves (Unaudited)***

The following tables show estimates of proved reserves prepared by the company's engineers and, for certain acquired Westport properties, by third-party reserve engineers, in accordance with the SEC definitions. Data is shown for crude oil in millions of barrels, for natural gas in billions of cubic feet (Bcf) at a pressure base of 14.73 pounds per square inch and for total proved reserves in millions of barrels of oil equivalent. For total proved reserves, natural gas is converted to barrels of oil equivalent using a conversion factor of six thousand cubic feet of natural gas per barrel.

During 2004, the company expanded the involvement of third-party engineers in its reserve estimation processes. In July 2004, the company engaged Netherland, Sewell & Associates, Inc. (NSAI), to provide independent third-party review of the company's procedures and methods for reserves estimation. The purpose of NSAI's review was to verify that the reserve estimates prepared by the company's internal technical staff are in accordance with the guidelines and definitions of the SEC using generally accepted petroleum engineering and evaluation principles. During 2004, NSAI's review covered approximately 50% of the company's year-end 2003 proved reserve base (43% of year-end 2004 proved reserves). NSAI determined that the procedures and methods were reasonable and estimates had been prepared in accordance with Rule 4-10(a) of SEC Regulation S-X and generally accepted petroleum engineering and evaluation principles. A copy of the NSAI report is included as exhibit 99 to this annual report on Form 10-K.

In addition to NSAI's review, certain reserves acquired in the Westport merger in June 2004 were estimated by Ryder Scott Company L.P. under an ongoing agreement with Westport. Following the merger, Kerr-McGee retained Ryder Scott Company L.P. to complete a year-end 2004 evaluation of both the Greater Natural Buttes and Moxa Arch fields, both of which were major assets acquired in the Westport transaction. Including these fields, approximately 55% of the company's 2004 proved reserve base was reviewed by a third party in 2004. In 2005, the company plans to expand third-party reviews to cover approximately 75 percent of its year-end 2004 proved reserves.

The company's estimates of proved reserves are derived from data prepared by its engineers using available geological and reservoir data, as well as production performance data. These estimates are reviewed annually and revised, either upward or downward, as warranted by additional data. Revisions of previous estimates can occur due to changes in, among other things, reservoir performance, prices, economic conditions and governmental restrictions. For example, a decrease in commodity price could result in a decrease in proved reserves as the economic limit of a reservoir might be reached sooner. Conversely, an improvement in reservoir performance could result in an increase in proved reserves, indicating higher ultimate recovery from previous estimates.

The company's engineering staff is highly skilled with average industry experience of over 20 years. The company relies primarily on its internal engineering expertise, augmented by third-party engineering oversight and advice to ensure objective estimates of the company's proved reserves. The company mitigates the inherent risks associated with reserve estimation through a comprehensive reserves administration process. The company's process includes:

- Independent third-party procedures and methods assessment
- Internal peer review and third-party assessment of all individually significant reserve additions (defined as those in excess of 5 million barrels of oil equivalent on a net basis)
- Annual internal review of about 80% of the company's total proved reserves

The following tables summarize changes in the estimated quantities of proved reserves for the three years ended December 31, 2004. As described in Note 2, we completed a merger with Westport in 2004, which resulted in reserve additions of 281 million barrels of oil equivalent. During 2002, we experienced significant downward reserve revisions primarily related to the Leadon field in the U.K. North Sea. Additionally, during 2002 we completed a divestiture program to rationalize noncore oil and gas properties. For further details related to the Leadon field and asset divestitures refer to discussion included in Note 25.

Crude Oil, Condensate and Natural Gas Liquids (Millions of barrels)	Continuing Operations: United States	North Sea	China	Other International	Total Continuing Operations	Discontinued Operations	Total
Proved developed and undeveloped reserves –							
Balance December 31, 2001	317	388	35	39	779	62	841
Revisions of previous estimates	8	(101)	1	–	(92)	–	(92)
Purchases of reserves in place	1	13	–	–	14	–	14
Sales of reserves in place	(62)	(61)	–	(37)	(160)	(51)	(211)
Extensions, discoveries and other additions	6	1	–	–	7	–	7
Production	(29)	(38)	(1)	(2)	(70)	(2)	(72)
Balance December 31, 2002	241	202	35	–	478	9	487
Revisions of previous estimates	7	(7)	2	–	2	–	2
Purchases of reserves in place	3	12	–	–	15	–	15
Sales of reserves in place	(16)	–	(3)	–	(19)	(9)	(28)
Extensions, discoveries and other additions	55	14	6	–	75	–	75
Production	(28)	(26)	(1)	–	(55)	–	(55)
Balance December 31, 2003	262	195	39	–	496	–	496
Revisions of previous estimates	9	6	1	–	16	–	16
Purchases of reserves in place	67	–	–	–	67	–	67
Sales of reserves in place	(10)	–	–	–	(10)	–	(10)
Extensions, discoveries and other additions	14	1	–	–	15	–	15
Production	(32)	(23)	(3)	–	(58)	–	(58)
Balance December 31, 2004	310	179	37	–	526	–	526

Natural Gas (Billions of cubic feet)	United States	North Sea	China	Other International	Total Continuing Operations	Discontinued Operations	Total
Proved developed and undeveloped reserves –							
Balance December 31, 2001	2,945	527	–	–	3,472	535	4,007
Revisions of previous estimates	(70)	(7)	–	–	(77)	–	(77)
Purchases of reserves in place	17	16	–	–	33	–	33
Sales of reserves in place	(76)	(9)	–	–	(85)	(535)	(620)
Extensions, discoveries and other additions	204	6	–	–	210	–	210
Production	(241)	(37)	–	–	(278)	–	(278)
Balance December 31, 2002	2,779	496	–	–	3,275	–	3,275
Revisions of previous estimates	(10)	11	–	–	1	–	1
Purchases of reserves in place	57	30	–	–	87	–	87
Sales of reserves in place	(77)	–	–	–	(77)	–	(77)
Extensions, discoveries and other additions	152	8	–	–	160	–	160
Production	(230)	(35)	–	–	(265)	–	(265)
Balance December 31, 2003	2,671	510	–	–	3,181	–	3,181
Revisions of previous estimates	86	(98)	–	–	(12)	–	(12)
Purchases of reserves in place	1,289	–	–	–	1,289	–	1,289
Sales of reserves in place	(27)	–	–	–	(27)	–	(27)
Extensions, discoveries and other additions	59	–	–	–	59	–	59
Production	(306)	(31)	–	–	(337)	–	(337)
Balance December 31, 2004	3,772	381	–	–	4,153	–	4,153

Crude Oil, Condensate and Natural Gas Liquids (Millions of barrels)	Continuing Operations United States	North Sea	China	Other International	Total Continuing Operations	Discontinued Operations	Total
Proved developed reserves –							
December 31, 2002	147	130	2	–	279	5	284
December 31, 2003	122	125	–	–	247	–	247
December 31, 2004	197	120	16	–	333	–	333
Natural Gas (Billions of cubic feet)							
Proved developed reserves –							
December 31, 2002	1,658	168	–	–	1,826	–	1,826
December 31, 2003	1,502	113	–	–	1,615	–	1,615
December 31, 2004	2,620	135	–	–	2,755	–	2,755

The following presents the company's barrel of oil equivalent proved developed and undeveloped reserves based on approximate heating value (6 Mcf equals 1 barrel).

Barrels of Oil Equivalent (Millions of barrels)	Continuing Operations United States	North Sea	China	Other International	Total Continuing Operations	Discontinued Operations	Total
Proved developed and undeveloped reserves –							
Balance December 31, 2001	808	476	35	39	1,358	151	1,509
Revisions of previous estimates	(4)	(102)	1	–	(105)	–	(105)
Purchases of reserves in place	3	16	–	–	19	–	19
Sales of reserves in place	(74)	(63)	–	(37)	(174)	(140)	(314)
Extensions, discoveries and other additions	40	2	–	–	42	–	42
Production	(69)	(44)	(1)	(2)	(116)	(2)	(118)
Balance December 31, 2002	704	285	35	–	1,024	9	1,033
Revisions of previous estimates	5	(5)	2	–	2	–	2
Purchases of reserves in place	12	17	–	–	29	–	29
Sales of reserves in place	(29)	–	(3)	–	(32)	(9)	(41)
Extensions, discoveries and other additions	81	15	6	–	102	–	102
Production	(66)	(32)	(1)	–	(99)	–	(99)
Balance December 31, 2003	707	280	39	–	1,026	–	1,026
Revisions of previous estimates	24	(11)	1	–	14	–	14
Purchases of reserves in place	282	–	–	–	282	–	282
Sales of reserves in place	(15)	–	–	–	(15)	–	(15)
Extensions, discoveries and other additions	24	1	–	–	25	–	25
Production	(83)	(28)	(3)	–	(114)	–	(114)
Balance December 31, 2004	939	242	37	–	1,218	–	1,218

(Millions of equivalent barrels)	Continuing Operations United States	North Sea	China	Other International	Total Continuing Operations	Discontinued Operations	Total
Proved developed reserves –							
December 31, 2002	423	158	2	–	583	5	588
December 31, 2003	372	144	–	–	516	–	516
December 31, 2004	634	142	16	–	792	–	792
Proved undeveloped reserves –							
December 31, 2002	281	127	33	–	441	4	445
December 31, 2003	335	136	39	–	510	–	510
December 31, 2004	305	100	21	–	426	–	426

33. **Standardized Measure of and Reconciliation of Changes in Discounted Future Net Cash Flows (Unaudited)**

The standardized measure of future net cash flows presented in the following table was computed using year-end prices and costs and a 10% discount factor. The future income tax expense was computed by applying the appropriate year-end statutory rates, with consideration of future tax rates already legislated, to the future pretax net cash flows less the tax basis of the properties involved. However, the company cautions that actual future net cash flows may vary considerably from these estimates. Although the company's estimates of total proved reserves, development costs and production rates were based on the best information available, the development and production of the oil and gas reserves may not occur in the periods assumed. Actual prices realized, costs incurred and production quantities may vary significantly from those used. Therefore, such estimated future net cash flow computations should not be considered to represent the company's estimate of the expected revenues or the current value of existing proved reserves.

(Millions of dollars)	Future Cash Inflows (1)	Future Production Costs	Future Development Costs	Future Income Taxes	Future Net Cash Flows	10% Annual Discount	Standardized Measure of Discounted Future Net Cash Flows
2004							
United States	$33,512	$ 7,976	$2,752	$7,158	$15,626	$6,549	$ 9,077
North Sea	8,927	2,988	999	1,863	3,077	934	2,143
China	986	306	83	113	484	148	336
Total	$43,425	$11,270	$3,834	$9,134	$19,187	$7,631	$11,556 (2)
2003							
United States	$23,850	$5,002	$2,067	$5,467	$11,314	$4,721	$6,593
North Sea	7,770	2,437	790	1,552	2,991	970	2,021
China	1,114	306	130	178	500	208	292
Total	$32,734	$7,745	$2,987	$7,197	$14,805	$5,899	$8,906 (2)
2002							
United States	$17,195	$4,909	$1,642	$3,372	$ 7,272	$2,951	$4,321
North Sea	7,332	1,484	602	1,887	3,359	923	2,436
China	1,052	280	154	162	456	214	242
Total continuing operations	25,579	6,673	2,398	5,421	11,087	4,088	6,999 (2)
Discontinued operations	224	84	11	34	95	32	63
Total	$25,803	$6,757	$2,409	$5,455	$11,182	$4,120	$7,062

(1) Future cash inflows from sales of crude oil and natural gas are based on average year-end prices of $37.02, $29.05 and $28.61 per barrel of oil and $5.78, $5.77 and $3.63 per Mcf of natural gas for 2004, 2003 and 2002, respectively.

(2) Estimated future net cash flows before income tax expense, discounted at 10%, totaled approximately $17.0 billion, $13.2 billion and $10.3 billion, for 2004, 2003 and 2002, respectively.

The changes in the standardized measure of future net cash flows are presented below for each of the past three years:

(Millions of dollars)	**2004**	2003	2002
Net change in sales prices and production costs	**$ 2,069**	$ 3,308	$ 6,870
Sales revenues less production costs	**(3,454)**	(2,383)	(1,795)
Purchases of reserves in place	**3,850**	344	243
Extensions, discoveries and other additions	**438**	1,183	347
Revisions in quantity estimates	**(66)**	63	(1,433)
Sales of reserves in place	**(204)**	(255)	(1,920)
Current-period development costs incurred	**928**	573	743
Changes in estimated future development costs	**(852)**	(472)	(209)
Accretion of discount	**1,323**	1,033	701
Change in income taxes	**(1,097)**	(978)	(1,336)
Timing and other	**(285)**	(572)	(137)
Net change	**2,650**	1,844	2,074
Total at beginning of year	**8,906**	7,062	4,988
Total at end of year	**$11,556**	$ 8,906	$ 7,062

34. **Quarterly Financial Information (Unaudited)**

A summary of quarterly consolidated results for 2004 and 2003 is presented below. The quarterly per-share amounts do not add to the annual amounts due to the effects of the weighted average of stock issued and the anti-dilutive effect of convertible debentures in certain quarters.

(Millions of dollars, except per-share amounts)	Revenues [1]	Operating Profit [1]	Income from Continuing Operations [1]	Net Income	Income from Continuing Operations per Common Share Basic [1]	Diluted [1]
2004 Quarter Ended –						
March 31	**$1,109**	**$ 334**	**$155**	**$152**	**$1.55**	**$1.44**
June 30	**1,091**	**277**	**115**	**111**	**1.11**	**1.05**
September 30	**1,361**	**216**	**9**	**7**	**.06**	**.06**
December 31	**1,596**	**341**	**136**	**134**	**.90**	**.87**
Total	**$5,157**	**$1,168**	**$415**	**$404**	**3.29**	**3.19**
2003 Quarter Ended –						
March 31	$1,069	$ 269	$104	$ 70	$1.04	$ .99
June 30	1,024	258	76	70	.76	.73
September 30	980	227	30	29	.30	.30
December 31	1,007	212	54	50	.54	.54
Total	$4,080	$ 966	$264	$219	2.63	2.58

(1) As discussed in Note 25, in the fourth quarter of 2004, criteria for presenting results of operations of the company's forest products business as discontinued operations were met. Therefore, revenues, results of operations and per-share data in the above table differ from the quarterly amounts disclosed in the respective Forms 10-Q.

The company's common stock is listed for trading on the New York Stock Exchange and at year-end 2004 was held by approximately 21,685 Kerr-McGee stockholders of record and Oryx, HS Resources and Westport owners, who have not yet exchanged their stock. The ranges of market prices and dividends declared during the last two years for Kerr-McGee Corporation are as follows:

	Market Prices				Dividends per Share	
	2004		2003			
	High	**Low**	High	Low	**2004**	2003
Quarter Ended –						
March 31	**$53.39**	**$46.92**	$44.90	$37.82	**$.45**	$.45
June 30	**56.00**	**47.05**	48.59	39.90	**.45**	.45
September 30	**58.67**	**50.49**	45.50	41.08	**.45**	.45
December 31	**63.24**	**55.57**	47.20	40.10	**.45**	.45

35. Subsequent Events

Company to Pursue the Separation of its Chemical Business

The company announced on March 8, 2005, that its Board of Directors (the Board) authorized management to proceed with its proposal to pursue alternatives for the separation of the chemical business, including a spinoff or sale.

Share Repurchase Program

On March 8, 2005, the Board authorized the company to proceed with a share repurchase program initially set at $1 billion. The Board expects to expand the share repurchase program as the chemical business separation proceeds.

The timing and final number of shares to be repurchased under an expanded repurchase program will depend on the outcome of the chemical business separation, as well as business and market conditions, applicable securities law limitations and other factors. Shares may be purchased from time to time in the open market or through privately negotiated transactions at prevailing prices, and the program may be suspended or discontinued at any time without prior notice.

Recommendation to Increase Authorized Stock

The company's Board of Directors in the March 8, 2005 meeting recommended for the stockholders to approve an increase of the authorized number of shares of the company's common stock, par value $1.00 share, from 300 million shares to 500 million shares.

Conversion of 5.25% Debentures

In February 2005, the company called for redemption all of the $600 million aggregate principal amount of its 5.25% convertible subordinated debentures due 2010 at a price of 102.625%. Prior to March 4, 2005, the redemption date, all of the debentures were converted by the holders into approximately 9.8 million shares of common stock.

Ten-Year Financial Summary (Millions of dollars, except per-share amounts)

	2004 [a]	2003	2002 [b]	2001 [c]	2000	1999	1998	1997	1996	1995
Statement of Operations Summary										
Revenues	**$ 5,157**	$ 4,080	$ 3,515	$ 3,451	$ 3,955	$ 2,602	$ 2,079	$ 2,527	$ 2,663	$ 2,350
Costs and operating expenses	**4,201**	3,313	3,834	2,730	2,551	2,216	2,489	1,949	2,052	2,242
Interest and debt expense	**245**	251	275	195	208	191	159	141	145	194
Total costs and expenses	**4,446**	3,564	4,109	2,925	2,759	2,407	2,648	2,090	2,197	2,436
	711	516	(594)	526	1,196	195	(569)	437	466	(86)
Other income (expense)	**(40)**	(57)	(31)	231	50	36	40	81	109	147
Benefit (provision) for income taxes	**(256)**	(195)	35	(277)	(434)	(100)	179	(178)	(222)	44
Income (loss) from continuing operations	**$ 415**	$ 264	$ (590)	$ 480	$ 812	$ 131	$ (350)	$ 340	$ 353	$ 105
Effective Income Tax Rate	**38.2%**	42.5%	(5.6)%	36.6%	34.8%	43.3%	(33.8)%	34.4%	38.6%	72.1%
Net income (loss) from continuing operations per common share										
Basic	**$ 3.29**	$ 2.63	$ (5.89)	$ 4.94	$ 8.69	$ 1.51	$ (4.04)	$ 3.91	$ 4.01	$ 1.18
Diluted	**$ 3.19**	$ 2.58	$ (5.89)	$ 4.68	$ 8.08	$ 1.51	$ (4.04)	$ 3.89	$ 3.99	$ 1.18
Shares outstanding at year-end (thousands)	**151,889**	100,860	100,384	100,185	94,485	86,483	86,367	86,794	87,032	89,613
Per share information										
Dividends declared	**$ 1.80**	$ 1.80	$ 1.80	$ 1.80	$ 1.80	$ 1.80	$ 1.80	$ 1.80	$ 1.64	$ 1.55
Stockholders' equity [d]	**32.86**	23.79	23.01	28.83	25.01	17.19	15.58	17.88	14.59	12.47
Market high for the year	**63.24**	48.59	63.58	74.10	71.19	62.00	73.19	75.00	74.13	64.00
Market low for the year	**46.92**	37.82	38.02	46.94	39.88	28.50	36.19	55.50	55.75	44.00
Market price at year-end	**57.79**	46.49	44.30	54.80	66.94	62.00	38.25	63.31	72.00	63.50
Balance Sheet Information										
Property, plant and equipment – net	**$10,827**	$ 7,399	$ 6,978	$ 7,320	$ 5,178	$ 3,967	$ 4,038	$ 3,838	$ 3,652	$ 3,784
Total assets	**14,518**	10,250	9,909	11,076	7,666	5,899	5,451	5,339	5,194	5,006
Long-term debt	**3,236**	3,081	3,798	4,540	2,244	2,496	1,978	1,736	1,809	1,683
Total debt	**3,699**	3,655	3,904	4,574	2,425	2,525	2,250	1,766	1,849	1,938
Stockholders' equity	**5,318**	2,636	2,536	3,174	2,633	1,492	1,346	1,558	1,279	1,124
Cash Flow Information										
Net cash provided by operating activities	**$ 2,050**	$ 1,518	$ 1,448	$ 1,143	$ 1,840	$ 708	$ 418	$ 1,114	$ 1,144	$ 732
Capital expenditures [e]	**1,340**	1,162	1,272	1,864	896	571	1,106	904	884	795
Dividends paid	**205**	181	181	173	166	138	86	85	83	79
Treasury stock purchased	**–**	–	–	–	–	–	25	60	195	45
Ratios										
Current ratio	**.8**	.8	.8	1.2	1.0	1.4	.8	1.0	1.2	.9
Average price/earnings ratio	**17.7**	19.9	NM	12.8	6.6	27.6	NM	14.9	13.9	42.5
Total debt to total capitalization	**41%**	58%	61%	59%	48%	63%	63%	53%	59%	63%
Employees										
Total wages and benefits	**$ 558**	$ 541	$ 412	$ 369	$ 333	$ 327	$ 359	$ 367	$ 367	$ 402
Number of employees at year-end	**4,084**	3,915	4,470	4,638	4,426	3,653	4,400	4,792	4,827	5,176

(a) As described in Note 2 to the Consolidated Financial Statements, on June 25, 2004, the company completed a merger with Westport Resources Corporation.

(b) 2002 loss from continuing operations includes an asset impairment charge of $652 million. See Note 25 to the Consolidated Financial Statements.

(c) On August 1, 2001, the company completed an acquisition of HS Resources for a total cost of $1.8 billion, consisting of cash of $955 million, assumption of debt of $506 million and issuance of 5.1 million common shares. Additionally, effective January 1, 2001, the company implemented FAS 133, "Accounting for Derivatives and Hedging Activities" (FAS 133), as amended. In conjunction with implementation, the company recorded the fair value of its derivative instruments on the balance sheet, including options embedded in the company's debt exchangeable for stock (DECS) of Devon Energy Corporation owned by the company. Further, the company chose to reclassify a portion of Devon shares owned from available-for-sale to trading category. As a result, the company recognized, as a component of other income (expense), an unrealized gain on securities of $181 million.

(d) Stockholder's equity per share for all periods presented reflects the effect of potential dilution, assuming potentially issuable shares are issued at the end of the reporting period.

(e) Inclusive of dry hole costs and exclusive of acquisition cost (net of cash acquired).

Ten-Year Operating Summary

	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995
Exploration and Production										
Crude oil and condensate production –										
(thousands of barrels per day)										
United States	**88.1**	76.5	81.3	77.7	73.7	79.3	66.2	70.6	73.8	74.8
North Sea	**62.3**	71.6	102.8	101.9	117.7	102.9	87.4	83.3	86.5	91.9
China	**8.4**	2.1	3.3	3.8	4.5	5.2	7.6	8.7	3.7	–
Other international	**–**	–	3.9	5.5	4.5	4.3	5.7	7.0	11.2	16.4
Total	**158.8**	150.2	191.3	188.9	200.4	191.7	166.9	169.6	175.2	183.1
Average price of crude oil sold (per barrel) –										
United States	**$29.11**	$26.14	$21.56	$22.05	$27.50	$16.90	$12.78	$18.45	$19.56	$15.78
North Sea	**26.50**	25.82	22.41	23.23	27.92	17.88	12.93	18.93	19.60	16.56
China	**32.37**	29.66	24.84	21.94	27.54	15.23	11.79	17.71	19.53	–
Other international	**–**	–	20.28	19.14	24.55	12.99	7.23	12.60	14.53	14.91
Average	**$28.23**	$26.04	$22.04	$22.60	$27.69	$17.30	$12.63	$18.40	$19.26	$16.10
Natural gas sales (MMcf per day)	**921**	726	760	596	531	580	584	685	781	809
Average price of natural gas sold (per Mcf)	**$ 5.13**	$ 4.37	$ 2.95	$ 3.83	$ 3.87	$ 2.38	$ 2.13	$ 2.44	$ 2.11	$ 1.63
Net exploratory wells drilled [(1)] –										
Productive	**13.6**	6.7	4.8	2.4	1.3	1.7	4.4	7.7	6.9	4.7
Dry	**15.3**	17.0	17.2	11.4	10.5	3.8	14.4	7.4	5.5	11.2
Total	**28.9**	23.7	22.0	13.8	11.8	5.5	18.8	15.1	12.4	15.9
Net development wells drilled [(1)] –										
Productive	**429.8**	244.4	196.3	128.6	47.8	46.2	62.3	95.8	143.3	135.9
Dry	**7.5**	1.1	1.4	6.6	5.4	5.9	9.0	7.0	13.1	11.9
Total	**437.3**	245.5	197.7	135.2	53.2	52.1	71.3	102.8	156.4	147.8
Undeveloped net acreage (thousands) [(1)] –										
United States	**3,367**	2,884	2,399	2,382	2,020	1,560	1,487	1,353	1,099	1,280
North Sea	**392**	369	871	932	923	861	908	523	560	570
China	**1,469**	1,488	1,046	917	961	346	1,481	2,183	925	341
Other international	**30,455**	47,178	41,514	50,450	25,117	18,693	13,235	12,447	3,631	3,690
Total	**35,683**	51,919	45,830	54,681	29,021	21,460	17,111	16,506	6,215	5,881
Developed net acreage (thousands) [(1)] –										
United States	**2,134**	1,352	1,266	1,192	729	796	810	830	871	1,190
North Sea	**122**	136	109	149	115	105	115	70	79	58
China	**9**	–	17	17	17	19	19	19	19	19
Other international	**–**	–	1	639	639	766	593	182	179	188
Total	**2,265**	1,488	1,393	1,997	1,500	1,686	1,537	1,101	1,148	1,455
Estimated proved reserves [(1)] –										
(millions of equivalent barrels)	**1,218**	1,026	1,033	1,509	1,088	920	901	892	849	864
Chemicals										
Titanium dioxide pigment production (thousands of tonnes)	**549**	532	508	483	480	320	284	168	155	154

[(1)] Includes discontinued operations.

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

None.

Item 9A. Controls and Procedures

As of the end of the period covered by this report, an evaluation was carried out under the supervision and with the participation of the company's management, including its Chief Executive Officer and Chief Financial Officer, of the effectiveness of the company's disclosure controls and procedures pursuant to Exchange Act Rule 13a-15. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the company's disclosure controls and procedures are effective in alerting them in a timely manner to material information relating to the company (including its consolidated subsidiaries) required to be included in the company's periodic SEC filings. There was no change in the company's internal control over financial reporting that occurred during the fourth quarter of 2004 that has materially affected or is reasonably likely to materially affect the company's internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

This report is included in Item 8 on page 75 of this report and is incorporated by reference.

PART III

Item 10. Directors and Executive Officers of the Registrant

(a) Identification of directors -

For information required under this section, reference is made to the "Director Information" section of the company's proxy statement made in connection with its Annual Stockholders' Meeting to be held on May 10, 2005.

(b) Identification of executive officers -

The information required under this section is set forth in the caption "Executive Officers of the Registrant" on pages 28 and 29 of this annual report on Form 10-K pursuant to Instruction 3 to Item 401(b) of Regulation S-K and General Instruction G(3) to Form 10-K.

(c) Compliance with Section 16(a) of the 1934 Act -

For information required under this section, reference is made to the "Section 16(a) Beneficial Ownership Reporting Compliance" section of the company's proxy statement made in connection with its Annual Stockholders' Meeting to be held on May 10, 2005.

(d) Code of Ethics for the Chief Executive Officer and Principal Financial Officers -

Information regarding the Code of Ethics for the Chief Executive Officer and Principal Financial Officers can be found in Items 1 and 2 of this annual report on Form 10-K under "Availability of Reports and Governance Documents."

Item 11. Executive Compensation

For information required under this section, reference is made to the executive compensation sections of the company's proxy statement made in connection with its Annual Stockholders' Meeting to be held on May 10, 2005.

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

Information regarding Kerr-McGee common stock that may be issued under the company's equity compensation plans as of December 31, 2004, is included in the following table:

	Number of shares of common stock to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of shares remaining available for future issuance under equity compensation plans [1]
Equity compensation plans approved by security holders	5,991,192	$54.84	2,576,646
Equity compensation plans not approved by security holders	1,525,463	48.88	592,217
Total	7,516,655	53.63	3,168,863

[1] Excludes shares to be issued upon exercise of outstanding options, warrants and rights.

The Kerr-McGee Corporation Performance Share Plan was approved by the Board of Directors in January 1998 but was not approved by the company's stockholders. This plan is a broad-based stock option plan that provides for the granting of options to purchase the company's common stock to full-time, nonbargaining-unit employees, except officers. A total of 1,500,000 shares of common stock were authorized to be issued under this plan. A copy of the plan document was attached as exhibit 10.19 to the company's December 31, 2002, Form 10-K and is incorporated by reference in exhibit 10.14 to the company's December 31, 2004 Form 10-K.

Awards under certain equity compensation plans of Oryx Energy Company and Westport Resources Corporation were assumed by the company in connection with its acquisitions of Oryx and Westport. The terms of those awards are governed by the Oryx and Westport plans, respectively. The plans, which provided for the granting of stock options to officers and employees of Oryx and Westport, did not require approval of Kerr-McGee stockholders. No further grants may be made under the Oryx or Westport plans.

For information required under Item 403 of Regulation S-K, reference is made to the "Ownership of Stock of the Company" section of the company's proxy statement made in connection with its Annual Stockholders' Meeting to be held on May 10, 2005.

Item 13. Certain Relationships and Related Transactions

None.

Item 14. Principal Accountant Fees and Services

For information required under this section, reference is made to the "Fees Paid to the Independent Auditors" section of the company's proxy statement made in connection with its Annual Stockholders' Meeting to be held on May 10, 2005.

PART IV

Item 15. Exhibits, Financial Statement Schedules, and Reports on Form 8-K

(a) 1. Financial Statements – See the Index to the Consolidated Financial Statements included in Item 8 of this annual report on Form 10-K.

(a) 2. Financial Statement Schedules – See the Index to the Financial Statement Schedules included in Item 8 of this annual report on Form 10-K.

(a) 3. Exhibits – The following documents are filed under Commission file numbers 1-16619 and 1-3939 as part of this report.

Exhibit No.

3.1 Amended and restated Certificate of Incorporation of Kerr-McGee Corporation, filed as Exhibit 4.1 to the company's Registration Statement on Form S-4 dated June 28, 2001, and incorporated herein by reference.

3.2 Amended and restated ByLaws of Kerr-McGee Corporation, filed as Exhibit 3.1 to the current report on Form 8-K dated January 18, 2005, and incorporated herein by reference.

4.1 Rights Agreement dated as of July 26, 2001, by and between the company and UMB Bank, N.A., filed as Exhibit 4.1 to the company's Registration Statement on Form 8-A filed on July 27, 2001, and incorporated herein by reference.

4.2 First Amendment to Rights Agreement, dated as of July 30, 2001, by and between the company and UMB Bank, N.A., filed as Exhibit 4.1 to the company's Registration Statement on Form 8-A/A filed on August 1, 2001, and incorporated herein by reference.

4.3 Indenture dated as of November 1, 1981, between the company and United States Trust Company of New York, as trustee, relating to the company's 7% Debentures due November 1, 2011, filed as Exhibit 4 to Form S-16, effective November 16, 1981, Registration No. 2-772987, and incorporated herein by reference.

4.4 Indenture dated as of August 1, 1982, filed as Exhibit 4 to Form S-3, effective August 27, 1982, Registration Statement No. 2-78952, and incorporated herein by reference, and the first supplement thereto dated May 7, 1996, between the company and Citibank, N.A., as trustee, relating to the company's 6.625% notes due October 15, 2007, and 7.125% debentures due October 15, 2027, filed as Exhibit 4.1 to the Current Report on Form 8-K filed July 27, 1999, and incorporated herein by reference.

4.5 The company agrees to furnish to the Securities and Exchange Commission, upon request, copies of each of the following instruments defining the rights of the holders of certain long-term debt of the Registrant: the Note Agreement dated as of November 29, 1989, among the Kerr-McGee Corporation Employee Stock Ownership Plan Trust, referred to as the Trust, and several lenders, providing for a loan guaranteed by the company of $125 million to the Trust; the $150 million, $8^1/_8$% Note Agreement entered into by Oryx dated as of October 20, 1995, and due October 15, 2005; and the Credit Agreement dated as of November 10, 2004, between the company or certain subsidiary borrowers and various banks providing for revolving credit up to $1.5 billion through November 10, 2009. The total amount of securities authorized under each of such instruments does not exceed 10% of the total assets of the Registrant and its subsidiaries on a consolidated basis.

Exhibit No.

4.6 Kerr-McGee Corporation Direct Purchase and Dividend Reinvestment Plan filed on September 9, 2001, pursuant to Rule 424(b)(2) of the Securities Act of 1933 as the Prospectus Supplement to the Prospectus dated August 31, 2001, and incorporated herein by reference.

4.7 Fifth Supplement to the August 1, 1982, Indenture dated as of February 11, 2000, between the company and Citibank, N.A., as trustee, relating to the company's 5-1/4% Convertible Subordinated Debentures due February 15, 2010, filed as Exhibit 4.1 to Form 8-K filed February 4, 2000, and incorporated herein by reference.

4.8 Indenture dated as of August 1, 2001, between the company and Citibank, N.A., as trustee, relating to the company's $350 million, 5-3/8% notes due April 15, 2005; $325 million, 5-7/8% notes due September 15, 2006; $675 million, 6-7/8% notes due September 15, 2011; $500 million 7-7/8% notes due September 15, 2031; and $650 million, 6.95% notes due July 1, 2024, filed as Exhibit 4.1 to Form S-3 Registration Statement No. 333-68136 Pre-effective Amendment No. 1, and incorporated herein by reference.

10.1* Kerr-McGee Corporation Deferred Compensation Plan for Non-Employee Directors as amended and restated effective January 1, 2003, filed as Exhibit 10.1 to the Form 10-K for the year ended December 31, 2002, and incorporated herein by reference.

10.2* Kerr-McGee Corporation Executive Deferred Compensation Plan as amended and restated effective January 1, 2003, filed as Exhibit 10.4 to the Form 10-K for the year ended December 31, 2002, and incorporated herein by reference.

10.3* Benefits Restoration Plan as amended and restated effective May 1, 1999, filed as Exhibit 10.3 to the Form 10-K for the year ended December 31, 2003, and incorporated herein by reference.

10.4* First Supplement to Benefits Restoration Plan as amended and restated effective January 1, 2000, filed as Exhibit 10.4 to the Form 10-K for the year ended December 31, 2003, and incorporated herein by reference.

10.5* Second Supplement to Benefits Restoration Plan as amended and restated effective January 1, 2001, filed as Exhibit 10.5 to the Form 10-K for the year ended December 31, 2003, and incorporated herein by reference.

10.6* Kerr-McGee Corporation Supplemental Executive Retirement Plan as amended and restated effective February 26, 1999, filed as exhibit 10.6 to the report on Form 10-K for the year ended December 31, 2001, and incorporated herein by reference.

10.7* First Supplement to the Kerr-McGee Corporation Supplemental Executive Retirement Plan as amended and restated effective February 26, 1999, filed as exhibit 10.7 to the report on Form 10-K for the year ended December 31, 2001, and incorporated herein by reference.

10.8* Amended and Restated Second Supplement to the Kerr-McGee Corporation Supplemental Executive Retirement Plan as amended and restated effective February 26, 1999.

10.9* The Long Term Incentive Program as amended and restated effective May 9, 1995, filed as Exhibit 10.5 on Form 10-Q for the quarter ended March 31, 1995, and incorporated herein by reference.

Exhibit No.

10.10* The Kerr-McGee Corporation 1998 Long Term Incentive Plan effective January 1, 1998, filed as Exhibit 10.4 on Form 10-Q for the quarter ended March 31, 1998, and incorporated herein by reference.

10.11* The Kerr-McGee Corporation 2000 Long Term Incentive Plan effective May 1, 2000, filed as Exhibit 10.4 on Form 10-Q for the quarter ended March 31, 2000, and incorporated herein by reference.

10.12* The 2002 Long Term Incentive Plan effective May 14, 2002, filed as Exhibit 10.2 on Form 10-Q for the quarter ended June 30, 2002, and incorporated herein by reference.

10.13* The 2002 Annual Incentive Compensation Plan effective May 14, 2002, filed as Exhibit 10.1 on Form 10-Q for the quarter ended June 30, 2002, and incorporated herein by reference.

10.14* Kerr-McGee Corporation Performance Share Plan effective January 1, 1998, filed as Exhibit 10.19 to the Form 10-K for the year ended December 31, 2002, and incorporated herein by reference.

10.15* Oryx Energy Company 1992 Long-Term Incentive Plan, as amended and restated May 1, 1997, filed as Exhibit 10.15 to the Form 10-K for the year ended December 31, 2003, and incorporated herein by reference.

10.16* Oryx Energy Company 1997 Long-Term Incentive Plan, as amended and restated May 1, 1997, filed as Exhibit 10.16 to the Form 10-K for the year ended December 31, 2003, and incorporated herein by reference.

10.17* Amended and restated Agreement, restated as of January 11, 2000, between the company and Luke R. Corbett filed as Exhibit 10.10 on Form 10-K for the year ended December 31, 2000, and incorporated herein by reference.

10.18* Amended and restated Agreement, restated as of January 11, 2000, between the company and Kenneth W. Crouch filed as Exhibit 10.11 on Form 10-K for the year ended December 31, 2000, and incorporated herein by reference.

10.19* Amended and restated Agreement, restated as of January 11, 2000, between the company and Robert M. Wohleber filed as Exhibit 10.12 on Form 10-K for the year ended December 31, 2000, and incorporated herein by reference.

10.20* Amended and restated Agreement, restated as of January 11, 2000, between the company and Gregory F. Pilcher filed as Exhibit 10.14 on Form 10-K for the year ended December 31, 2000, and incorporated herein by reference.

10.21* Agreement, dated as of September 3, 2002, between the company and David A. Hager.

10.22* Registration Rights Agreement, dated as of April 6, 2004, among Kerr-McGee Corporation, Westport Energy LLC, Medicor Foundation and EQT Investments, LLC, filed as Exhibit 99.7 to the company's Current Report on Form 8-K dated April 8, 2004, and incorporated herein by reference.

10.23* Compensation Plan for Directors and tax reimbursement arrangement, filed as Exhibit 10.1 to the current report on Form 8-K dated January 18, 2005, and incorporated herein by reference.

Exhibit No.

10.24* 2005 Performance Measures for Annual Incentive Compensation Plan, filed as Exhibit 10.2 to the current report on Form 8-K dated January 18, 2005, and incorporated herein by reference.

10.25 Voting Agreement, dated as of April 6, 2004, among Kerr-McGee Corporation, Belfer Corp., Renee Holdings Partnership, L.P., Vantz Limited Partnership, LDB Two Corp., Belfer Two Corp., Liz Partners, L.P., filed as Exhibit 99.2 to the company's Current Report on Form 8-K dated April 8, 2004, and incorporated herein by reference.

10.26 Voting Agreement, dated as of April 6, 2004, among Kerr-McGee Corporation and EQT Investments, LLC., filed as Exhibit 99.3 to the company's Current Report on Form 8-K dated April 8, 2004, and incorporated herein by reference.

10.27 Voting Agreement, dated as of April 6, 2004, among Kerr-McGee Corporation and Medicor Foundation, filed as Exhibit 99.4 to the company's Current Report on Form 8-K dated April 8, 2004, and incorporated herein by reference.

10.28 Voting Agreement, dated as of April 6, 2004, among Kerr-McGee Corporation and Westport Energy LLC., filed as Exhibit 99.5 to the company's Current Report on Form 8-K dated April 8, 2004, and incorporated herein by reference.

10.29 Voting Agreement, dated as of April 6, 2004, among Kerr-McGee Corporation and Donald D. Wolf, filed as Exhibit 99.6 to the company's Current Report on Form 8-K dated April 8, 2004, and incorporated herein by reference.

10.30 Amended and Restated Gas Purchase Agreement, dated July 1, 1998, among Oryx Gas Marketing Limited Partnership, Sun Operating Limited Partnership and Producers Energy Marketing, LLC, filed as Exhibit 10.23 to the Amendment to Form 10-K for the year ended December 31, 2003, and incorporated herein by reference.

10.31 Amendment to Amended and Restated Gas Purchase Agreement, dated May 1, 2000, among Oryx Gas Marketing Limited Partnership, Kerr-McGee Oil & Gas Corporation, Kerr-McGee Oil and Gas Onshore LP, and Cinergy Marketing & Trading, LLC, filed as Exhibit 10.24 to the Amendment to Form 10-K for the year ended December 31, 2003, and incorporated herein by reference.

10.32 Amendment No. 2 to Amended and Restated Gas Purchase Agreement, dated July 1, 2002, among Oryx Gas Marketing Limited Partnership, Kerr-McGee Oil & Gas Corporation, Kerr-McGee Oil and Gas Onshore LP, and Cinergy Marketing & Trading, LLC, filed as Exhibit 10.25 to the Amendment to Form 10-K for the year ended December 31, 2003, and incorporated herein by reference.

10.33 Letter Agreement, dated May 23, 2003, amending Amended and Restated Gas Purchase Agreement, dated July 1, 1998, among Kerr-McGee Oil & Gas Corporation, Kerr-McGee Oil and Gas Onshore LP, and Cinergy Marketing & Trading, LLC, filed as Exhibit 10.26 to the Amendment to Form 10-K for the year ended December 31, 2003, and incorporated herein by reference.

10.34* Oryx Energy Company Executive Retirement Plan, as amended and restated January 1, 1995.

12 Computation of ratio of earnings to fixed charges.

21 Subsidiaries of the Registrant.

Exhibit No.

23.1	Consent of Ernst & Young LLP.
23.2	Consent of Netherland, Sewell & Associates, Inc.
23.3	Consent of Ryder Scott Company, L.P.
24	Powers of Attorney.
31.1	Certification pursuant to Securities Exchange Act Rule 15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification pursuant to Securities Exchange Act Rule 15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99	Report of Netherland, Sewell & Associates, Inc.

*These exhibits relate to the compensation plans and arrangements of the company.

KERR-McGEE CORPORATION AND SUBSIDIARY COMPANIES
VALUATION ACCOUNTS AND RESERVES

(Millions of dollars)	Balance at Beginning of Year	Additions: Charged to Profit and Loss	Additions: Charged to Other Accounts	Deductions from Reserves	Balance at End of Year
Year Ended December 31, 2004					
Deducted from asset accounts					
Allowance for doubtful notes and accounts receivable	$19	$3	$2	$1	$23
Valuation allowance for deferred tax assets	9	1	–	2	8
Warehouse inventory obsolescence	8	5	–	1	12
Total	$36	$9	$2	$4	$43
Year Ended December 31, 2003					
Deducted from asset accounts					
Allowance for doubtful notes and accounts receivable	$19	$ 1	$ –	$ 1	$19
Valuation allowance for deferred tax assets	–	9	–	–	9
Warehouse inventory obsolescence	4	6	–	2	8
Total	$23	$ 16	$ –	$ 3	$36
Year Ended December 31, 2002					
Deducted from asset accounts					
Allowance for doubtful notes and accounts receivable	$21	$ –	$ –	$ 2	$19
Warehouse inventory obsolescence	5	1	–	2	4
Total	$26	$ 1	$ –	$ 4	$23

SIGNATURES

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

KERR-McGEE CORPORATION

By: Luke R. Corbett*
Luke R. Corbett, Director
Chief Executive Officer

March 13, 2005
Date

By: (Robert M. Wohleber)
Robert M. Wohleber
Senior Vice President and
Chief Financial Officer

By: (John M. Rauh)
John M. Rauh
Vice President and Controller
and Chief Accounting Officer

* By his signature set forth below, John M. Rauh has signed this Annual Report on Form 10-K as attorney-in-fact for the officer noted above, pursuant to power of attorney filed with the Securities and Exchange Commission.

By: (John M. Rauh)
John M. Rauh

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

By: Luke R. Corbett*
Luke R. Corbett, Director

By: William E. Bradford*
William E. Bradford, Director

By: Sylvia A. Earle*
Sylvia A. Earle, Director

By: David C. Genever-Watling*
David C. Genever-Watling, Director

March 13, 2005
Date

By: Martin C. Jischke*
Martin C. Jischke, Director

By: Leroy C. Richie*
Leroy C. Richie, Director

By: William F. Wallace*
William F. Wallace, Director

By: Farah M. Walters*
Farah M. Walters, Director

By: Ian L. White-Thomson*
Ian L. White-Thomson, Director

* By his signature set forth below, John M. Rauh has signed this Annual Report on Form 10-K as attorney-in-fact for the directors noted above, pursuant to the powers of attorney filed with the Securities and Exchange Commission.

By: (John M. Rauh)
John M. Rauh

Stockholder and investor information

Stock Exchange Listing
Kerr-McGee common stock is listed on the New York Stock Exchange under the ticker symbol KMG.

2005 Annual Meeting
Kerr-McGee's annual meeting will be held at 9 a.m. Central Time on May 10, 2005, in the Robert S. Kerr Auditorium at Kerr-McGee Center in Oklahoma City.

Stockholder Assistance
Contact UMB Bank, N.A., of Kansas City, Missouri, at (877) 860-5820 or (800) 884-4225 toll-free in the U.S. and Canada for assistance with:

- ☐ Direct deposit of cash dividends
- ☐ Direct stock purchase and dividend reinvestment plan
- ☐ Transfer of stock certificates
- ☐ Replacement of lost or destroyed stock certificates and dividend checks

Stockholder Information and Publications
Contact the Office of the Corporate Secretary at (800) 786-2556 toll-free in the U.S. and Canada for general information and assistance or to request the company's annual report on Form 10-K and quarterly reports on Form 10-Q, as filed with the U.S. Securities and Exchange Commission, and the company's annual report.

Information also is available on the company's website, including webcasts of conference calls discussing quarterly financial and operating results.

Direct Purchase and Dividend Reinvestment Plan
This plan allows stockholders to buy Kerr-McGee common stock directly from the company and to reinvest quarterly dividends in additional shares. The company pays all fees and commissions for these services. For a prospectus, please call (800) 786-2556 toll-free in the U.S. and Canada.

Investor Information
Stockholders, security analysts and other interested parties may direct inquiries to Richard C. Buterbaugh, Vice President of Investor Relations, at (866) 378-9899 toll-free in the U.S. and Canada.

Transfer Agent and Registrar
UMB Bank, N.A.
Securities Transfer Division
Post Office Box 410064
Kansas City, MO 64141-0064
(877) 860-5820 and (800) 884-4225
toll-free in the U.S. and Canada

Corporate Headquarters
Kerr-McGee Corporation
Kerr-McGee Center
123 Robert S. Kerr Avenue
Oklahoma City, OK 73102

Mailing address:
Post Office Box 25861
Oklahoma City, OK 73125

(405) 270-1313

Website: www.kerr-mcgee.com

Forward-Looking Information

The company makes certain forward-looking statements in this annual report that are subject to risks and uncertainties. These statements regarding the company's or management's intentions, beliefs or expectations, or that otherwise speak to future events, are based on the information currently available to management. These forward-looking statements include those statements preceded by, followed by or that otherwise include the words "believes," "expects," "anticipates," "intends," "estimates," "projects," "target," "budget," "goal," "plans," "objective," "outlook," "should," or similar words. In addition, any statements regarding possible commerciality, development plans, capacity expansions, drilling of new wells, ultimate recoverability of reserves, future production rates, future cash flows and changes in any of the foregoing are forward-looking statements. Future results and developments discussed in these statements may be affected by numerous factors and risks, such as the accuracy of the assumptions that underlie the statements, the success of the oil and gas exploration and production program, drilling risks, the market value of Kerr-McGee's products, uncertainties in interpreting engineering data, demand for consumer products for which Kerr-McGee's businesses supply raw materials, the financial resources of competitors, changes in laws and regulations, the ability to respond to challenges in international markets, including changes in currency exchange rates, political or economic conditions in areas where Kerr-McGee operates, trade and regulatory matters, general economic conditions, and other factors and risks discussed herein and in the company's U.S. Securities and Exchange Commission (SEC) filings, and many such factors and risks are beyond Kerr-McGee's ability to control or predict. Forward-looking statements are not guarantees of performance. Actual results and developments may differ materially from those expressed or implied in this annual report. Readers are cautioned not to place any undue reliance on any forward-looking statements. Forward-looking statements speak only as of the date of this annual report. Kerr-McGee undertakes no obligation to update publicly any forward-looking statements, whether as a result of new information, future events or otherwise. For such statements, Kerr-McGee claims the protection of the safe harbor for "forward-looking statements" set forth in the Private Securities Litigation Reform Act of 1995.

The SEC permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves. We use certain terms in this annual report, such as "probable/possible resources," which the SEC's guidelines strictly prohibit us from including in filings with the SEC. Investors are urged to consider closely the disclosures and risk factors in our Forms 10-K and 10-Q, File No. 1-16619, available from Kerr-McGee's offices or website, www.kerr-mcgee.com. These forms also can be obtained from the SEC by calling 1-800-SEC-0330.

KERR-McGEE CORPORATION

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