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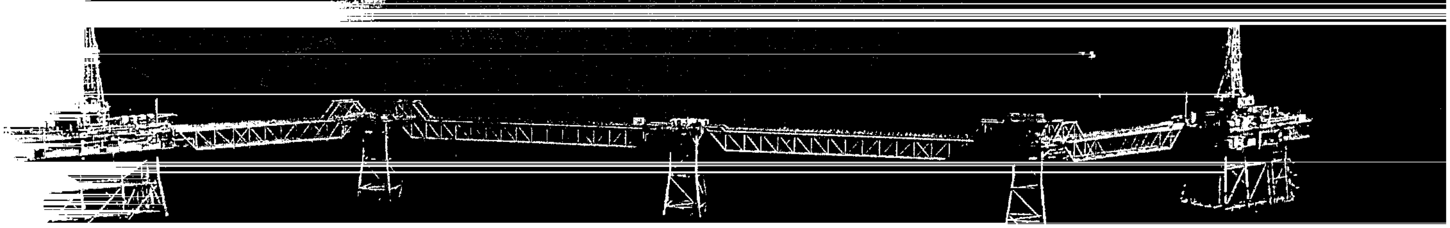

McMoRan Exploration Co.
2003 Annual Report and Form 10-K

On the cover: Drilling rigs in the OCS 310/Louisiana State Lease 340 area (upper page) where highly positive exploratory drilling during 2003 resulted in significant production for the joint venture program at our JB Mountain and Mound Point prospects. These prospects are located in the Gulf of Mexico and are part of our shallow-water, deep gas exploration strategy. Our business strategy also includes reconfiguring existing infrastructure at Main Pass Block 299 (lower page) in the establishment of the Main Pass Energy Hub™, where we are proposing an offshore terminal to receive and process liquefied natural gas (LNG), as well as store and distribute natural gas.

McMoRan Exploration Co.

TO OUR SHAREHOLDERS:

We achieved significant progress during 2003 in building real value for our shareholders and in positioning McMoRan to build significant value in the future. Market fundamentals for natural gas have become increasingly attractive as evidence continues to emerge that domestic supply of natural gas is failing to keep pace with growing demand. Industry and public officials, including Federal Reserve Chairman Alan Greenspan, have focused attention to this issue and its potential to limit economic expansion in the U.S., prompting a flurry of on-going media interest.

McMoRan's business plan is ideally suited for opportunities from improving U.S. natural gas markets. We are leading the industry to the Gulf of Mexico shelf in search of gas at depths greater than 15,000 feet. The Minerals Management Service has recognized this opportunity and in November 2003 increased its estimate of undiscovered gas resources on the Gulf of Mexico shelf by 175 percent to 55 trillion cubic feet – based on five successful exploratory wells, three of which we participated in developing prospects. Identifying these high quality prospects requires the use of established, traditional geologic analysis. The inability of modern seismic technology to develop hydrocarbon indicators or "bright spots" at these depths has resulted in relatively few wells being drilled to explore for these large potential reservoirs associated with deep structures on the Gulf of Mexico shelf. Our knowledge about the Gulf of Mexico shelf uniquely qualifies us for this challenge.

We are also at the forefront of efforts to develop domestic liquefied natural gas (LNG) terminals to meet our nation's demand for natural gas. In February 2004, we filed a license application with the U.S. Coast Guard for our proposed Main Pass Energy Hub™ (MPEH™), which has the potential to be one of the first new LNG import terminals to begin operations. The MPEH™ will use the significant existing infrastructure at our discontinued Main Pass sulphur operations offshore, which are being reconfigured to create a facility to receive and process an average of 1 billion cubic feet of LNG per day, as well as store and distribute natural gas. In addition to benefiting from the availability of existing infrastructure, this facility is in close proximity to shipping channels and natural gas pipelines and would provide significant natural gas storage capacity in an on-site, two-mile-wide salt dome. Its offshore location in over 200 feet of water would allow quick, safe access by LNG carriers of all sizes and provide construction timing advantages over other proposed projects. We anticipate the MPEH™ could be in operation by the end of 2007.

There is a common thread to the elements of our business plan which we call **"Back to the Future."** As we implement this plan, McMoRan will be –

- Leading the exploration and production industry **back** to the Gulf of Mexico shelf to help meet the nation's **future** energy needs
- Using fundamental geology in identifying drilling prospects, drawing on our team's **past** experience on the shelf and onshore in the Gulf Coast Region to provide the opportunity for **future** success
- Going **back** to our Main Pass infrastructure and finding an exciting new use for these facilities as an LNG terminal and an energy hub that would provide value for our shareholders long into the **future**

Our deep shelf exploration strategy is based on our knowledge and understanding of structural geology in the Gulf of Mexico. Our primary focus in this region is on shallow-water "deep shelf" natural gas exploration and production opportunities. The deep shelf of the Gulf of Mexico provides attractive drilling opportunities because the shallow water depths and close proximity to existing oil and gas production infrastructure allows discoveries to generate production and cash flows quickly.

During the past year highly positive drilling and establishment of significant production at our JB Mountain and Mound Point prospects were important developments for our company. Three wells are currently producing in the area, with gross production currently approximating 85 million cubic feet of natural gas per day. The year 2004 will be important in the on-going development of these two fields. Currently, two rigs are drilling to develop these prospects and we expect continued aggressive development activities on these projects. We are currently paying none of the program's exploration and development costs. Once 100 billion cubic feet of natural gas equivalent are produced to the program's interest, we will participate in 50 percent of subsequent revenues and costs.

In January 2004 we announced a participation agreement with a new exploration partner which enables us to proceed in significantly broader exploratory drilling outside of the JB Mountain/Mound Point area. Under this multi-year exploration joint venture, a private exploration and production company has committed to spend a minimum of $200 million for its share of the joint venture's exploration costs. The private company will participate for 40 percent of McMoRan's interests in prospects drilled during this period. Over the next twelve months, McMoRan and its partner plan to participate in at least 10 wells. To date, we have commenced drilling one well under the new arrangement and expect to commence three others during the first quarter of 2004.

We plan to participate in an active exploration program during 2004 through our program interest in the JB Mountain/Mound Point area and through our new joint venture for other Gulf of Mexico exploration drilling opportunities. Our current exploration acreage position consists of approximately 185,000 gross acres remaining from a position of 750,000 gross acres in 2000. Over the last three years, we have undertaken an intensive effort to evaluate this acreage position and identify opportunities to pursue our "deep shelf" strategy. Outside the JB Mountain/Mound Point area, we have identified 17 prospects, most of which are deep exploration targets for natural gas near existing production infrastructure in the shallow waters of the Gulf of Mexico. We estimate gross unrisked potential for nine of these prospects, that we expect to drill in 2004 to be approximately 4 Tcfe* with unrisked potential net to our interest of over 1 Tcfe*. Additionally we assign over 4.5 Tcfe* of gross unrisked potential with 600 Bcfe* of net unrisked potential to our JB Mountain/Mound Point prospects.

During 2003, McMoRan completed a $130 million private placement of 6% convertible senior notes due July 2, 2008. Net proceeds from the notes totaled approximately $100 million, after using approximately $23 million to purchase U.S. government securities held in escrow to pay future interest payments. The notes are convertible into shares of McMoRan's common stock at $14.25 per share, representing a 25 percent premium over the closing price on June 26, 2003 of McMoRan's shares. The success of this offering is allowing us to retain a greater ownership in our planned drilling activities and in our MPEH™ project. At the end of 2003, our unrestricted cash position totaled approximately $100 million.

In a move to strengthen our corporate governance structure, McMoRan separated the roles of Chairman and Chief Executive Officer in February 2004. Glenn A. Kleinert has been named President and Chief Executive Officer. James R. Moffett and Richard C. Adkerson will continue to serve as Co-Chairmen of the Board. McMoRan will be managed through an Office of the Chairman consisting of Messrs. Moffett, Adkerson and Kleinert. The Office of the Chairman will direct the business activities of McMoRan, with Mr. Moffett continuing to focus on exploration activities and business strategy, including McMoRan's efforts to develop the MPEH™ offshore Louisiana. Mr. Adkerson will focus on financial and administrative activities and financial strategy, including the commercial and financing activities for the MPEH.™ Mr. Kleinert is responsible for executive management functions including acreage development and production activities. B. M. Rankin, Jr.

continues as Vice Chairman of McMoRan's Board of Directors. C. Howard Murrish, Executive Vice President, will continue his key role in McMoRan's oil and gas exploration activities.

We want to thank our Board of Directors and our employees, whose support, hard work, encouragement, wisdom and guidance has contributed significantly to McMoRan's past successes and the development of its exciting future opportunities.

Sincerely,

James R. Moffett Co-Chairman of the Board	Richard C. Adkerson Co-Chairman of the Board	Glenn A. Kleinert President and Chief Executive Officer

March 15, 2004

**Cautionary Statement:* *The Securities and Exchange Commission (SEC) requires oil and gas companies, in their filings with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. We are permitted to use other estimates in non-filed documents, however, including this letter to our shareholders. Accordingly we have provided in this letter estimates of "gross unrisked potential" and "net unrisked potential" to indicate the estimated relative size of our exploration prospects. The SEC's guidelines prohibit us from including any estimates of recoverable quantities other than proved oil and gas reserves that comply with the SEC's definitions in filings with the SEC and those estimates are included in our attached Form 10-K, which investors are urged to consider closely.*

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

[X] **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2003
or
[ ] **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from ____________ to ____________

Commission file number 001-07791

McMoRan Exploration Co.

(Exact name of registrant as specified in its charter)

Delaware	**72-1424200**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
1615 Poydras Street New Orleans, Louisiana	**70112**
(Address of principal executive offices)	*(Zip Code)*

Registrant's telephone number, including area code: (504) 582-4000

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

Title of each class	Name of each exchange on which registered
Common Stock, Par Value $0.01 Per Share	New York Stock Exchange
Preferred Stock Purchase Rights	New York Stock Exchange
6% Convertible Senior Notes due 2008	New York Stock Exchange

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 (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [X]   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. [X]

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

The aggregate market value of the voting stock held by non-affiliates of the registrant was approximately $126,573,000 on March 1, 2004, and was approximately $103,878,000 on June 30, 2003.

On March 1, 2004, there were issued and outstanding 17,094,333 shares of the registrant's Common Stock, par value $0.01 per share, and on June 30, 2003 there were issued and outstanding 16,696,476 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Proxy Statement submitted to the registrant's stockholders in connection with the registrant's 2004 Annual Meeting of Stockholders to be held on May 6, 2004 are incorporated by reference into Part III (Items 10, 11, 12, 13 and 14) of this report.

McMoRan Exploration Co.
Annual Report on Form 10-K for
the Fiscal Year ended December 31, 2003

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PART I

Items 1. and 2. Business and Properties

All of our periodic report filings with the Securities and Exchange Commission (SEC) pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, are available, free of charge, through our website located at www.mcmoran.com, including our annual reports on Form 10-K, quarterly reports on Form 10-Q, and current reports on Form 8-K, and any amendments to those reports. These reports and amendments are available through our website as soon as reasonably practicable after we electronically file or furnish such materials to the SEC. All references to Notes in this report on Form 10-K refers to the Notes to the Consolidated Financial Statements located in Item 8. of this Form 10-K.

OVERVIEW

We have provided definitions for some of industry terms we use in a glossary on page 22.

About the Company. We engage in the exploration, development and production of oil and gas offshore in the Gulf of Mexico and onshore in the Gulf Coast region, with a focus on the significant reserve potential we believe is represented by large deep structures lying below reservoirs where significant reserves have been produced in the shallow waters of the Gulf of Mexico. We are also pursuing the establishment of an energy hub at our former sulphur facilities at Main Pass Block 299 (Main Pass) in the Gulf of Mexico. The energy hub project includes transforming the existing Main Pass facilities into a liquefied natural gas (LNG) terminal. During 2002 we exited the sulphur business, which involved the purchasing, transporting, terminaling, processing and marketing of sulphur.

During the past twelve months we have reported positive drilling results at federal lease OCS 310 (JB Mountain prospect) and Louisiana State Lease 340 (Mound Point prospect) through our May 2002 farm-out agreement with El Paso Production Company (El Paso) (see "Oil and Gas Operations – Farm-Out Arrangement with El Paso" below). This success has reinforced our belief in the potential for significant hydrocarbon accumulations in large structures at underground depths of greater than 15,000 feet in the shallow waters of the Gulf of Mexico and lying below reservoirs where significant production has already occurred. Under our farm-out agreement with El Paso, El Paso is funding all of the program's costs attributable to the prospects and will retain the program's interests until aggregate production for the prospects totals 100 billion cubic feet of natural gas equivalent (Bcfe) attributable to the program's net revenue interest, at which point 50 percent of the program's interests, including working interests and the obligation to fund future capital requirements, would revert to us. The JB Mountain and Mound Point prospects are located in water depths of 10 feet in an area where the program controls approximately 45,000 acres within an 80,000-acre exploration area, including a portion of OCS lease 310 and portions of the adjoining Louisiana State Lease 340.

In January 2004, we announced the formation of a multi-year exploration joint venture with a private exploration and production company, which has committed to fund a minimum of $200 million for its share of the joint venture's exploration costs. The joint venture will be outside the JB Mountain and Mound Point areas. This recent agreement is described below in "Oil and Gas Operations – Near-Term Drilling Activities".

As of January 1, 2004, we owned or controlled interests in 52 oil and gas leases in the Gulf of Mexico and onshore Louisiana and Texas covering approximately 201,000 gross acres (approximately 95,000 acres net to our interests). For more information regarding our acreage position see "Oil and Gas Operations - Acreage" below.

At December 31, 2003, our estimated proved oil and gas reserves, as prepared by an independent petroleum engineering firm and using the definitions required by the SEC, totaled approximately 16.9 Bcfe, consisting of 13.6 Bcf of natural gas and 0.5 MMbls of oil and condensate. For more information regarding our reserve information see "Oil and Gas Operations – Oil and Gas Reserves" below.

Prior to mid-2002, we had significant sulphur operations in addition to our oil and gas activities. In June 2002, we sold substantially all of the assets used in our sulphur transportation and teminaling business. In 2000, we ceased our sulphur mining operations and have recently completed substantial reclamation activities at our former offshore sulphur mining facilities. Since ceasing sulphur production from our offshore Main Pass mine in 2000, we have been pursuing potential alternative uses of these facilities. We believe that the offshore platforms and related structures, together with the related two-mile diameter caprock and salt dome, have the potential for a variety of commercial activities, including facilities to receive and process LNG and store and distribute natural gas. See "Main Pass Energy Hub™ Project" below for more information regarding our pursuit of the establishment of an energy hub at Main Pass. We have also applied for permits that would allow us to use the facilities as a disposal site for non-hazardous oilfield waste.

Subsidiaries. We have two significant wholly owned subsidiaries, McMoRan Oil & Gas LLC (MOXY), which conducts all our oil and gas operations, and Freeport-McMoRan Energy LLC (Freeport Energy). During 2003, in connection with our efforts to establish an energy hub at Main Pass, Freeport Energy changed its name from Freeport-McMoRan Sulphur LLC (Note 1).

Business Strategy. Our near-term business strategy is to continue to aggressively pursue exploration activities in the Gulf of Mexico, primarily involving high-risk, high-potential, deep-gas exploration prospects located in the shallow waters the Gulf of Mexico near existing oil and gas production infrastructure, and to establish the Main Pass Energy Hub™. Our efforts will require significant expenditures during 2004 and 2005. To meet these capital requirements, we enhanced our financial flexibility during 2003 by issuing $130 million of convertible debt (Note 5) and by recently forming a multi-year joint venture with a private exploration and production company that committed to fund a minimum of $200 million for its share of the joint venture's exploration costs.

Over the longer-term, we will need to develop additional financial resources to finance our exploration program and development of the Main Pass Energy Hub™ Project through the discovery, development and production of oil and gas reserves or through third party financing arrangements. In addition, we may require additional capital resources as a result of our efforts to identify and exploit new business opportunities. We believe our recent successful oil and gas exploration and development results, together with the significant exploration potential of our remaining acreage position, the sharing of exploration costs with our new joint venture partner and the opportunity to participate in new businesses through the Main Pass Energy Hub™, will enable us to achieve these goals. The ultimate outcome of these efforts is subject to significant uncertainties, many of which are beyond our control, including exploration risks, oil and gas prices and production rates, reliance on third parties to fund and conduct exploration and development activities on the JB Mountain and Mound Point prospects, and the feasibility of the Main Pass Energy Hub™ Project, among other factors. For additional information on these risks and others see "Risk Factors" below.

OIL AND GAS OPERATIONS

Oil and Gas Properties. As of December 31, 2003, we owned or controlled interests in 72 oil and gas leases in the Gulf of Mexico and onshore Louisiana and Texas covering approximately 295,000 gross acres (approximately 147,000 acres net to our interests). On January 1, 2004, our acreage position was reduced, reflecting the expiration of our offshore exploration agreement with Texaco Exploration and Production Inc. (Texaco), a subsidiary of Chevron Texaco Corp. As of January 1, 2004, we owned or controlled interests in 52 oil and gas leases covering approximately 201,000 gross acres (approximately 95,000 net to our interests). This acreage includes approximately 49,000 gross and 10,000 net acres associated with our potential reversionary interests. Potential reversionary interests refer to interests in properties that we have farmed-out or sold but which may revert to us upon the achievement of a specified production threshold or the receipt of specified net production proceeds.

Ryder Scott Company, L.P., an independent petroleum engineering firm, estimated our proved oil and gas reserves at December 31, 2003 to be approximately 16.9 Bcfe, consisting of 13.6 Bcf of natural gas and 0.5 MMBbls of crude oil and condensate using the definitions required by the SEC (see "Oil and Gas Reserves" below). These estimated amounts include approximately 2.5 Bcfe of reserves associated with reversionary interests in properties we sold in February 2002 (see "Disposition of Oil and Gas Properties" below) but do not include any reserves that may be associated with our JB Mountain and Mound Point discoveries, or the estimated 1.6 MMBbls of crude oil (or 9.4 Bcf gas equivalent) reserves associated with our 33.3 percent equity interest in the Main Pass oil operations (see "K1 Business Alliance" below). For additional information regarding our estimated reserves, see Note 13. Our production during 2003 totaled approximately 2.0 Bcf of natural gas and 0.1 MMBbls of oil and condensate or an aggregate of 2.8 Bcfe.

Near-Term Drilling Activities. Over the past several years, we have focused our exploration activities on identifying an inventory of exploration prospects within our significant acreage position. These efforts resulted in the identification of 20 high-potential, high-risk prospects, most of which are deep-gas targets near existing infrastructure in the shallow waters of the Gulf of Mexico. We have identified 17 such prospects outside the JB Mountain and Mound Point areas. In January 2004, we announced the formation of a multi-year exploration joint venture with a private exploration and production company, which has committed to fund a minimum of $200 million for its share of the joint venture's exploration costs. The new partner will participate for 40 percent of our interests in prospects located outside the JB Mountain and Mound Point areas. The table below sets forth approximate information with respect to prospects we have tentatively identified for drilling over the next twelve months. Our plans are subject to change based on various factors, as described in "Risk Factors" below.

Field, Lease or Well	Working Interest[a] (%)	Net Revenue Interest[a] (%)	Water Depth (feet)	Planned Depth of Well[b] (feet)
Prospects Subject to Multi-Year Joint Venture: [c]				
Garden Banks Block 625 (Dawson Deep) [d]	30.0	24.0	2,900	26,000
Eugene Island Blocks 212/213 (Phoenix) [e]	40.0	28.1	100	22,000
Vermilion Block 208 (Lombardi Deep) [e]	45.0	36.2	115	19,000
Eugene Island Block 193 (Deep Tern Miocene) [e]	33.8	26.7	90	20,350
Eugene Island Block 97/108 (Thunderbolt Intermediate)	24.0	17.3	32	18,500
East Breaks Block 301 (Conga)	40.0	30.2	2,000	16,500
Louisiana State Lease 340 (Lighthouse Point – Southwest)	34.2	24.3	8	16,000
South Marsh Island Block 183 (Blackhawk)	42.0	33.7	360	17,000
Prospects subject to El Paso Farm-out Agreement [f]				
South Marsh Island Block 223 (OCS 310):				
JB Mountain No. 3	55.0	38.8	10	21,000
JB Mountain No. 4	55.0	38.8	10	21,000
Louisiana State Lease 340:				
Mound Point Offset No. 2	30.4	21.6	10	18,500
Mound Point - Horst Block	30.4	22.0	10	20,000
Mount Point – West Fault Block	30.4	21.6	10	18,700
Other:				
South Marsh Island Block 217 (Hurricane Upthrown) [g]	55.0	38.8	10	18,500

a. Interests as of February 29, 2004, which are subject to change based on participation elections of other partners.
b. Planned target measured depth, which is subject to change.
c. Assumes participation by our joint venture partner (see above) for 40 percent of our interests in prospects.
d. As discussed below, this well is currently in progress.
e. Prospects anticipated to commence drilling in the first quarter of 2004.
f. Under our farm-out program, El Paso currently holds our working and net revenue interests in these prospects, subject to a 50 percent reversionary interest. See "Farm-out Arrangement with El Paso."
g. El Paso has elected not to participate in any further exploration activities at the Hurricane prospect. Accordingly, we will pay 100 percent of the costs to drill and evaluate this second exploratory well. Our working interest will reduce to 55 percent at casing point. Interests are subject to change upon certain participation elections by third parties. This prospect is a follow-up to the initial Hurricane well drilled in 2003 (see below).

- **Garden Banks Block 625 (Dawson Deep)** – Exploratory drilling commenced on December 12, 2003. The well was drilled to a measured depth of 24,450 feet and encountered 165 feet of net pay over several productive intervals. The partners then agreed to side track the well to a down dip position as an appraisal well. As of March 12, 2004 the sidetrack well is drilling below 26,300 feet proceeding towards a total planned measured depth of approximately 26,900 feet.

- **South Marsh Island Block 217 (Hurricane)** – Drilling of an initial exploratory well commenced in August 2003. The Hurricane well was located approximately 2 miles northwest of the JB Mountain No. 1 discovery well. The Hurricane prospect is located on 9,500 acres within the OCS 310 (JB Mountain) area but is excluded from the El Paso farm-out arrangement. El Paso funded all the costs of drilling the well down to an election point (18,262 feet), where we elected to continue drilling the well to its final depth of 20,224 feet. Wireline logs indicated the well contained potential hydrocarbon accumulations. The well was completed and production tested but was determined to be non-commercial. The well was then plugged and abandoned. A second exploratory well is planned for the second half of 2004 to test the upthrown prospect based on the significant geologic data obtained from the initial Hurricane exploratory well.

The table below sets forth approximate information, as of December 31, 2003, with respect to our producing properties and two remaining prospects included in our farm-out arrangement with El Paso. For additional property information see "Other" and "Disposition of Oil and Gas Properties" below. Following the table is a summary of activities on these properties during the past three years.

Field, Lease or Well	Working Interest	Net Revenue Interest	Operator	Water Depth	Location Offshore Louisiana	Gross Acreage
	(%)	(%)		(in feet)	(miles)	
Producing						
Main Pass Block 299[(a)]	33.3	27.8 [(b)]	MMR [(c)]	210	32	1,125
Vermilion Block 160 Field Unit	41.8	35.8 [(b)]	MMR	100	42	2,813
Eugene Island Blocks 193/208/215	53.4	41.7	MMR	100	50	10,000
Eugene Island Block 193 C-1 well	42.2 [(d)]	33.4 [(d)]	MMR	90	50	-
Eugene Island Blocks 97/108	38.0	27.2	DVN [(e)]	90	50	9,375
Ship Shoal Block 296[(f)]	12.4	8.7	APC [(g)]	260	62	5,000
Farm-out [(h)]						
South Marsh Island Block 223	55.0	38.8	CVX [(i)]	10		- [(j)]
Louisiana State Lease 340	30.4	21.6	CVX	10		- [(j)]

a. Sold in mid-December 2002 to a joint venture in which we retained a 33.3 percent equity interest. Ownership interests shown reflect our retained interest through the joint venture (see "K1 Business Alliance" below).
b. Subject to net profit interests of approximately 2.6 percent at the Vermilion Block 160 field unit and 50 percent at Main Pass.
c. MMR is our New York Stock Exchange ticker symbol.
d. Reflects the election of a third party to participate in 20 percent of our interests; amounts would increase to 50.1 percent working interest and 39.6 percent net revenue interest upon reaching payout.
e. Devon Energy Corporation.
f. We sold 80 percent of property interests effective January 1, 2002. We retain our interests in exploratory prospects lying 100 feet below the stratigraphic equivalent of the deepest currently producing interval. We also retain a potential reversionary interest in this property as well as two others (see "Disposition of Oil and Gas Properties" below).
g. Anadarko Inc. replaced us as operator of the field effective February 1, 2003.
h. In May 2002, we entered into an exploration arrangement with El Paso covering four of our deep-gas prospects. We retained a potential 50 percent reversionary interest in these prospects when the aggregate production from the prospects, net to the program's net revenue interests, exceeds 100 Bcfe. El Paso has relinquished its rights in two prospects following the drilling of a nonproductive exploratory well at each prospect.
i. Chevron Texaco Corporation. Chevron Texaco is operator for the producing wells at JB Mountain and Mound Point, while El Paso is currently the operator for drilling operations at the two prospects.
j. Prospects located in area where we participate in a program that controls an approximate 45,000-acre area within an 80,000-acre exploration position, which includes these leases, portions of OCS Lease 310 and adjoining portions of Louisiana State Lease 340.

Producing Properties. The following summarizes activities on our producing properties.

- **Vermilion Block 160 Field Unit.** We commenced production from two wells at this unit in 1995. In 1997, we discovered additional pay sands by drilling three additional development wells. We successfully completed certain recompletion activities at the field during the first quarter of 2003. During 2003, the field had intermittent production from three wells; however, two of wells have ceased production and we are currently evaluating alternatives regarding remedial operations to restore production. Average current gross production totals 2.4 MMcfe/d, 0.9 MMcfe/d net to us.

- **Eugene Island Blocks 193/208/215.** We re-established production from the field during the second quarter of 2000. During the fourth quarter of 2000, we performed remedial and recompletion work, which identified additional proved reserves. Average current gross production approximates 3.9 MMcfe/d, 1.7 MMcfe/d net to us.

- **Eugene Island Block 193.** During the fourth quarter of 2000, we initiated drilling the Eugene Island Block 193 (Deep Tern prospect) No. 3 (C-1) exploratory well. The well was drilled to a measured depth of approximately 17,200 feet. The well encountered 230 feet of net gas pay in two sands. The well commenced production in June 2001. The C-1 well's production utilizes the production facilities on the Eugene Island Block 193-A platform. After experiencing mechanical problems during the third quarter of 2002, production from the well was shut-in. We are considering alternatives, including the drilling of a substitute well in connection with our Deep Tern Miocene exploration activities, planned for the first quarter of 2004, to produce the reserves associated with the C-1 well (see "Near-Term Drilling Activities" above).

- **Eugene Island Blocks 97 and 108.** In late 2000, we drilled the Eugene Island Block 97 (Thunderbolt prospect) No.1 exploratory well to a depth of 17,030 feet and encountered 75 feet of net hydrocarbon pay in three sands. Production commenced in March 2001. In February 2001, we drilled the Thunderbolt No. 2 exploratory well and encountered approximately 160 feet of net gas pay. The well was completed and developed, with initial production commencing in June 2001. In September 2001, we drilled the Thunderbolt No. 3 exploratory well to a measured depth of 18,300 feet and encountered seven sand intervals with approximately 340 net feet of highly resistive sands indicating potential hydrocarbons by electronic line log. The No. 3 well commenced production in January 2002. The Nos. 1, 2 and 3 wells have been shut-in periodically subsequent to initial production in order to perform recompletion work to establish production from new intervals. The No. 2 and No. 3 wells are currently shut-in. We are planning remedial operations at the field during the first half of 2004 to increase its production. Currently the Thunderbolt field, including the Eugene Island Block 108 No. 7 well, is producing at an average gross rate of 1.9 MMcfe/d, 0.6 MMcfe/d net to us.

- **Ship Shoal Block 296.** In June 2000, we commenced drilling the Ship Shoal Block 296 (Raptor prospect) No. 1 exploratory well, which reached a depth of 12,800 feet and encountered 67 feet of net gas pay in two zones. During the third quarter of 2000 we drilled the No. 2 well, which delineated the reserves previously discovered by the No. 1 well. Development of the Raptor prospect was completed during the second quarter of 2001, with initial production commencing in June 2001. We sold 80 percent of our original 61.8 percent working interest and 43.5 percent net revenue interest in February 2002 (see "Disposition of Oil and Gas Properties" below and Note 4). Average current gross production for the well totals approximately 9.5 MMcfe/d, 0.8 MMcfe/d net to our interest.

Farm-Out Arrangement with El Paso. In May 2002, we entered into a farm-out agreement with El Paso for four of our shallow-water, deep-gas prospects. El Paso has completed drilling initial exploratory wells at each of the four prospects, which resulted in two discoveries. El Paso has relinquished its rights to the other two properties back to us. Under the program, El Paso is funding our share of the exploratory drilling and development costs of these prospects and will own 100 percent of the program's interests in the remaining two prospects, JB Mountain and Mound Point, until the prospect's aggregate production attributable to the program's net revenue interests reaches 100 Bcfe. After aggregate production of 100 Bcfe, ownership of 50 percent of the program's working and net revenue interests would revert to us.

- **"JB Mountain" at South Marsh Island Block 223.** Drilling commenced at the JB Mountain prospect, located in a water depth of 10 feet, in June 2002. The JB Mountain No. 1 well was drilled to a measured depth of approximately 22,000 and evaluated with wireline logs and formation tests, which indicated significant intervals of hydrocarbon pay. The well was completed and production commenced in June 2003. The No. 1 well is currently producing at a gross rate of approximately 27 Mmcfe/d. The JB Mountain No. 2 well commenced in June 2003. This development well was drilled to a total measured depth of 22,375 feet and wireline logs indicated that it encountered significant hydrocarbons in the "Gyrodina" sand section. The wireline logs confirm that the hydrocarbon intervals in the No. 2 well are structurally high to those identified in the No. 1 well as anticipated in the pre-drill geological prognosis. The No. 2 well was subsequently completed and placed on production in January 2004. The No. 2 well is currently producing at a gross rate of approximately 29 Mmcfe/d. On December 15, 2003, the JB Mountain No. 3 well commenced drilling. The well, which is located approximately one mile south of the No. 1 well, has been drilled to a depth of approximately 14,000 feet. Due to mechanical difficulties, the well has been plugged back for sidetracking, and is preparing to drill ahead towards its proposed total depth of 21,000 feet.

- **"Mound Point Offset" at Louisiana State Lease 340.** Drilling commenced at the Mound Point Offset well, located in a water depth of 10 feet, in February 2003. The well was drilled to a total depth of approximately 19,000 feet and encountered 120 feet of net gas pay in three sands. Development activities were subsequently completed and the well commenced production in early October 2003. The Mound Point well is currently producing at a gross rate of approximately 29 Mmcfe/d. The Mound Point Offset No. 2 well commenced on January 30, 2004. Drilling has reached a depth of approximately 9,000 feet, and is proceeding towards its planned total depth of 18,500 feet. The Mound Point Offset No. 2 well is located approximately 7,000 feet south-

southeast of the Mound Point Offset discovery well. The Mound Point Offset wells are located approximately one mile from the No. 2 exploratory well at Louisiana State Lease 340 that we drilled and completed during 2001 and flow tested in early 2002 (see "Other" below).

- **"Hornung" at Eugene Island Block 108**. Drilling commenced at the Hornung prospect, located in 28 feet of water, in April 2002. The well was drilled to a measured depth of 21,800 feet and encountered several zones below 17,000 feet, which showed resistivity potentially indicative of hydrocarbon bearing formations. However, it was determined that the well did not contain commercial quantities of hydrocarbons, and it was plugged and abandoned (Note 1). El Paso has relinquished its rights to this prospect back to us.

- **"Lighthouse Point – Deep" at South Marsh Island Block 207.** Drilling commenced at the Lighthouse Point – Deep prospect, located in a water depth of 10 feet, in June 2002. The well was drilled to a measured depth of approximately 17,900 feet. The well was determined not to contain commercial quantities of hydrocarbons and was plugged and abandoned. El Paso has relinquished its rights to this prospect back to us.

Other.

- **Main Pass Block 299.** We acquired the Main Pass oil operations as part of our acquisition of Freeport Energy in November 1998. As of December 31, 2003, cumulative gross production from the Main Pass oil operations totaled approximately 45.0 MMBbls. The Main Pass field was shut-in during February 2001 for platform and equipment maintenance. In June 2001, we acquired Homestake Sulphur Company LLC's 16.7 percent working interest and 13.8 percent net revenue interest in Main Pass in exchange for assuming their portion of the remaining reclamation obligations associated with the related oil facilities and the Main Pass sulphur mine. In December 2002, we sold our interest in the Main Pass oil operations to a joint venture, in which we retained a 33.3 percent equity interest. See "K1 Business Alliance" below.

- **West Cameron Block 616.** We discovered this field in 1996. During 1998, we drilled three development wells and installed an offshore platform. Production commenced at the field from five well completions in March 1999. Production from the field ceased in February 2002 and we farmed out our interests to a third party in June 2002. The third party has drilled four successful wells at the field and production from the field re-commenced during the first quarter of 2003. We retained a 5 percent overriding royalty interest, which will increase to 10 percent after the field's incremental aggregate production exceeds 12 Bcf. Currently the field is producing at 35.0 MMcfe/d, 1.8 MMcfe/d net to us. Based on current production rates the field is projected to exceed the incremental 12 Bcf of production by late 2004 or early 2005.

- **Louisiana State Lease 340 No. 2.** We commenced drilling the Louisiana State Lease 340 No. 2 exploratory well in February 2001 and reached 18,704 feet in August 2001. In January 2002, the well was perforated and flowed at various rates from 10 to 20 Mmcfe/d, until a failure of the cement isolating the hydrocarbon-bearing sands caused water encroachment of this well. Remedial operations were unsuccessful in eliminating the water encroachment, and the well has been temporarily abandoned while we evaluate further remedial alternatives.

- **Garden Banks Block 228.** In December 2002, drilling commenced on an exploratory well at Garden Banks 228 (Cyprus prospect). The Cyprus well was drilled to a measured depth of approximately 16,900 feet. Evaluation of the drilling results determined that the well did not contain commercial quantities of hydrocarbons and the well was plugged and abandoned.

- **Main Pass Block 97.** In April 2003, drilling commenced on the Main Pass Block 97 (Shiner) No. 1 exploratory well, which was drilled to an approximate depth of 9,300 feet. The well was deemed to be nonproductive and was plugged and abandoned. We participated in this well through the joint venture that purchased our oil operations at Main Pass (see "K1 Business Alliance" in Item 7. and 7A. of this Form 10-K).

Disposition of Oil and Gas Properties. In February 2002, we sold interests in three oil and gas properties for $60.0 million: Vermilion Block 196 (47.5 percent working interest and 34.2 percent net revenue interest); Main Pass Blocks 86/97 (71.3 percent working interest and 51.3 percent net revenue interest); and 80 percent of our interests in Ship Shoal Block 296. The sale was effective January 1, 2002. We retained interests in exploratory prospects lying 100 feet below the stratigraphic equivalent of the deepest currently producing interval at both Vermilion Block 196 and Ship Shoal Block 296. We used the proceeds from the sale to repay the $51.7 million of borrowings under our oil and gas bank credit facility, which was then terminated (Notes 4 and 5), and for working capital requirements.

The properties were sold subject to a reversionary interest after "payout," which would occur when the purchaser receives aggregate cumulative proceeds from the properties of $60.0 million plus an agreed upon annual rate of return. After payout, 75 percent of the interests sold would revert to us. Based on the projected future production from these properties and year-end 2003 natural gas and oil price projections, we believe that payout for these properties could occur by the end of 2004. Whether or not payout ultimately occurs will depend upon future production levels and future market prices of both natural gas and oil, among other factors. For additional information regarding this transaction, see "Capital Resources and Liquidity – Sales of Oil and Gas Properties" located in Items 7. and 7A., and Note 4 located elsewhere in this Form 10-K.

In December 2002, we formed a joint venture, K-Mc Ventures I LLC (K-Mc I), which acquired our Main Pass oil production facilities. See "K1 Business Alliance" below.

Oil and Gas Reserves. The following table summarizes our estimated proved reserves of natural gas (MMcf) and oil (barrels) at December 31, 2003 based on a reserve report prepared by Ryder Scott Company, L.P., an independent petroleum engineering firm, using the criteria for developing estimates of proved reserves established by the SEC.

Gas		Oil	
Proved Developed	Proved Undeveloped	Proved Developed	Proved Undeveloped
8,074	5,493	388,835	158,349

We sold a substantial portion of our proved reserves in 2002, as described above. The table above does not include (1) estimated proved developed reserves of approximately 1.6 million barrels of oil related to our 33.3 percent equity interest in K-Mc I or (2) any proved reserves attributable to our potential reversionary interests in the JB Mountain and Mound Point discoveries, which are subject to a farm-out agreement with El Paso (see "Farm-Out Arrangement with El Paso" above).

Estimates of proved reserves for wells with little or no production history are less reliable than those based on a long production history. Subsequent evaluation of the properties may result in variations in estimates of proved reserves, which may be substantial. We anticipate that we will require additional capital to develop and produce our proved undeveloped reserves. For additional information regarding our estimated proved reserves, see Note 13 and "Risk Factors."

The following table presents the estimated future net cash flows before income taxes, and the present value of estimated future net cash flows before income taxes, from the production and sale of our estimated proved reserves as determined by Ryder Scott at December 31, 2003. The present value amount is calculated using a 10 percent per annum discount rate as required by the SEC. In preparing these estimates, Ryder Scott used prices being received at December 31, 2003 for each property. The weighted average of these prices for all our properties with proved reserves was $32.49 per barrel of oil and $6.28 per Mcf for gas.

	Proved Developed	Proved Undeveloped	Total Proved
		(in thousands)	
Estimated undiscounted future net cash flows before income taxes:	$ 44,189	$ 20,795	$ 64,984
Present value of estimated future net cash flows before income taxes:	$ 34,594	$ 18,108	$ 52,702

You should not assume that the present value of estimated future net cash flows shown in the preceding table represents the current market value of our estimated natural gas and oil reserves as of the date shown or any other date. For additional information regarding our estimated proved reserves, see Note 13 and "Risk Factors."

We are periodically required to file estimates of our oil and gas reserves with various governmental authorities. In addition, from time to time we furnish estimates of our reserves to governmental agencies in connection with specific matters pending before them. The basis for reporting estimates of proved reserves in some of these cases is different from the basis used for the estimated proved reserves discussed above. Therefore, all proved reserve estimates may not be comparable. The major variations include differences in when the estimates are made, in the definition of proved reserves, in the requirement to report in some instances on a gross, net or total operator basis and in the requirements to report in terms of smaller geographical units.

Production, Unit Prices and Costs. The following table shows production volumes, average sales prices and average production (lifting) costs for our oil and gas sales for each period indicated. The relationship between our sales prices and production (lifting) costs depicted in the table is not necessarily indicative of our present or future results of operations.

	Years ended December 31,		
	2003	2002	2001
Net gas production (Mcf)	2,011,100	5,851,300 [a]	11,136,800 [a]
Net crude oil and condensate production, excluding Main Pass (Bbls)[a,b]	103,400	124,700	342,800
Net crude oil production from Main Pass (Bbls)[c]	-	1,001,900	993,300
Sales prices:			
Natural gas (per Mcf)	$ 5.64	$ 3.00	$ 3.59
Crude oil and condensate, excluding Main Pass (per Bbl)[d]	$31.03	$24.24	$24.62
Crude oil from Main Pass (per Bbl)	-	$22.03	$21.07
Production (lifting) costs[e]			
Per barrel for Main Pass[f]	-	$13.98	$19.66
Per Mcfe for other properties[g]	$2.70	$ 1.09	$ 1.13

a. Includes production from properties sold effective January 1, 2002. Our sales volumes attributable to these properties totaled approximately 856,000 Mcf of gas and 18,500 barrels of oil and condensate in 2002 and approximately 3,200,800 Mcf of gas and 147,300 barrels of oil and condensate in 2001.
b. The amount during 2003 excludes approximately 20,700 equivalent barrels of oil and condensate associated with $0.8 million of plant product revenues received for the value of such products recovered from the processing of our natural gas production. Our oil and condensate production excludes 26,100 and 81,100 equivalent barrels of oil associated with $0.9 million and $3.0 million of plant product revenues during 2002 and 2001, respectively.
c. We sold our interests in the oil producing assets at Main Pass to K-Mc I on December 16, 2002. During 2003, we sold our remaining Main Pass oil inventory, which approximated 4,200 barrels of oil, at an average sale price of $24.09 per barrel.
d. Realization does not include the effect of the plant product revenues discussed in (b) above.
e. Production costs exclude all depletion, depreciation and amortization associated with property and equipment. The components of production costs may vary substantially among wells depending on the production characteristics of the particular producing formation, method of recovery employed, and other factors. Production costs include charges under transportation agreements as well as all lease operating expenses.
f. Main Pass production costs include platform and equipment repair and maintenance costs that totaled $4.9 million in 2001, including $1.9 million in February 2001 when the field was shut-in. These costs contributed $4.97 per barrel to its lifting costs in 2001.
g. Production costs were converted to an Mcf equivalent on the basis of one barrel of oil being equivalent to six Mcf of natural gas. The production costs included workover expenses totaling $1.5 million or $0.58 per Mcfe, in 2003, $1.2 million, or $0.19 per Mcfe, in 2002 and $6.5 million, or $0.47 per Mcfe, in 2001.

Acreage. The following table shows the oil and gas acreage in which we held interests as of January 1, 2004. The table does not include the approximate 31,500 gross acres no longer associated with our offshore exploration agreement with Texaco (which expired on January 1, 2004), on which we have retained rights to conduct or commit to exploration activities through June 30, 2004. We acquire ownership interests in the Texaco acreage when we or others on our behalf, drill wells that are capable of producing reserves and commit to developing such wells. The table also excludes approximately 49,300 gross acres attributable to our potential reversionary interests (see "Farm-Out Arrangement with El Paso" and "Disposition of Oil and Gas Properties" above), including the acreage associated with our JB Mountain prospect at South Marsh Island Block 223 and our Mound Point prospect at Louisiana State Lease 340, and approximately 7,700 acres related to our interest in the Hurricane prospect at South Marsh Island Block 217. For more information regarding our acreage position see Note 2.

	Developed		Undeveloped	
	Gross Acres	Net Acres	Gross Acres	Net Acres
Offshore (federal waters)	31,251	17,054	55,398	38,113
Onshore Louisiana and Texas	-	-	25,375	14,589
Total at January 1, 2004	31,251	17,054	80,773	52,702

Oil and Gas Drilling Activity. The following table shows the gross and net number of productive, dry, in-progress and total exploratory and development wells that we drilled in each of the years presented as of December 31 for each year:

	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Productive	1	0.304	2	0.854 [a]	3	1.710
Dry	3 [b]	0.943	1	0.400 [c]	4	2.234
In-progress	2 [d]	0.575	2	0.776	1	0.304
Total	6	1.822	5	2.030	8	4.248
Development						
Productive	2 [e]	1.025	-	-	-	-
Dry	-	-	-	-	-	-
In-progress	1 [f]	0.550	-	-	-	-
Total	3	1.575	-	-	-	-

a. Includes 0.550 net interest attributable to the ownership interest in the JB Mountain No. 1 well that is part of our farm-out arrangement with El Paso (the program). The other productive well during 2002 was the Louisiana State Lease 340 No. 2 well.
b. Includes 0.570 reversionary interest in the Lighthouse Point Deep well that was in progress at December 31, 2002. Also includes the Garden Banks Block 228 well that was in progress at December 31, 2002 as well as the Main Pass Block 97 No. 1 well.
c. Reflects reversionary interest in the Eugene Island Block 108 (Hornung) well.
d. Includes the Garden Banks Block 625 (Dawson Deep) well and the South Marsh Island Block 217 well, which was determined to be non-commercial in January 2004.
e. Includes 0.475 net interest attributable to a well drilled at Vermilion Block 196, which we sold subject to a 75 percent reversionary interest in February 2002 (see "Disposition of Oil and Gas Properties" above). Also, reflects the program's net interest in the JB Mountain No. 2 well.
f. Reflects the program's net interest in the JB Mountain No. 3 well.

Marketing. We currently sell our natural gas in the spot market at prevailing prices. Prices on the spot market fluctuate with demand and for other reasons. We generally sell our crude oil and condensate one month at a time at prevailing prices.

MAIN PASS ENERGY HUB™ PROJECT

We believe that an energy hub, with facilities to receive and process LNG and to store and distribute natural gas, could potentially be developed using the infrastructure previously constructed by us for our former sulphur mining operations at Main Pass, which were discontinued in August 2000. We refer to this potential project as the Main Pass Energy Hub™ Project. We have completed conceptual and preliminary engineering for the project. In February 2004, pursuant with the requirements of U.S. Deepwater Port Act, we filed an application with the U.S. Coast Guard requesting a license that will authorize us to receive and process LNG and store and distribute natural gas at the facilities. The proposed terminal would be capable of receiving and conditioning 1 Bcf per day of LNG and is being designed to accommodate potential future expansions. We have also previously applied for permits that would allow us to use the facilities as a disposal site for non-hazardous oilfield waste.

A natural gas terminal at Main Pass has numerous potential advantages over other LNG sites including:

- Currently existing facilities, thus providing timing, construction and operating cost advantages over undeveloped locations.
- Initial natural gas storage capacity of 28 Bcf within the two-mile diameter caprock and salt dome at the location.
- Close proximity to existing shipping channels.
- Access to an existing pipeline system and potential to develop other pipeline interconnects that would facilitate the receipt and distribution of natural gas to premium gas markets.
- Possible security and environmental advantages because of its offshore location.
- The potential ability to handle a fleet of new LNG supertankers, which may have limited access to existing U.S. ports.

We are continuing to assess the feasibility of developing an LNG terminal at the Main Pass facilities. Accordingly, we have not yet decided to develop the project. In addition to completing a detailed engineering and financial assessment, we are pursuing regulatory approvals. The project will also require significant financing. Obtaining regulatory permits and pursuing commercial arrangements will involve significant expenditures. We are seeking commercial arrangements to form the basis for financing the project. While there can be no assurance that regulatory approvals and financing may be obtained at an acceptable cost, or on a timely basis or at all, our objective is to pursue both simultaneously in order to position this project to be one of the first U.S. offshore facilities to receive and process LNG and store and distribute natural gas. As discussed in "K1 Business Alliance" below, our joint venture partner holds an option to participate as a passive equity investor for up to 15 percent of our equity interest in the Main Pass Energy Hub™ Project. Financing arrangements may also reduce our equity interest in the project. See Item 3. "Legal Proceedings" included elsewhere in this Form 10-K for information regarding our involvement in litigation relating to our ownership interest in the Main Pass Energy Hub™ Project.

K1 BUSINESS ALLIANCE

In October 2002, we formed an alliance with K1 USA Ventures, Inc. and K1 USA Energy Production Corporation (K1 USA), subsidiaries of k1 Ventures Limited (collectively K1). We call this new business alliance K-Mc Energy Ventures. K-Mc Energy Ventures seeks to identify high-quality opportunities in the energy sector.

On December 16, 2002, we and K1 USA formed K-Mc I, which is owned 66.7 percent by K1 USA and 33.3 percent by us. K-Mc I acquired our Main Pass oil production facilities and K1 USA agreed to provide, if required by us, credit support of up to $10 million of the bonding requirements with the MMS related to the abandonment obligations for these oil facilities. We anticipated using the proceeds from this transaction to fully fund the Phase I reclamation costs at Main Pass. K1 USA also received stock warrants to acquire a total of 2.5 million shares of our common stock at $5.25 per share, with the warrant for approximately 1.74 million shares expiring in December 2007 and the remainder expiring in September 2008.

Until September 2003, K-Mc I also had the option, at K1 USA's discretion, to acquire from us the Main Pass facilities that will be used in the potential Main Pass Energy Hub™ Project. In September 2003, we jointly modified the K-Mc I transaction to eliminate that option, so that K1 USA now has the right to participate as a passive equity investor for up to 15 percent of our equity interest in the Main Pass Energy Hub™ Project. K1 USA would need to exercise that right upon the closing of any project financing arrangements by agreeing prospectively to fund 15 percent of our future contributions to the project. For more information regarding the K-Mc I joint venture see "K1 Business Alliance" in Items 7. and 7A. and Note 4 elsewhere in this Form 10-K.

In connection with our K-Mc Energy Ventures activities, we assisted K1 in their acquisition of a gas distribution utility in August 2003. We received a $1.5 million advisory fee in connection with our services. Under terms of a management services agreement, we will receive a $1.8 million fee over a twelve-month period, beginning in August 2003, for providing continuing services to the gas distribution utility.

DISCONTINUED SULPHUR OPERATIONS

Background. Until mid-2000, our sulphur business consisted of two principal operations, sulphur services and sulphur mining. Our sulphur services involved two principal components, the purchase and resale of recovered sulphur and sulphur handling operations. During 2000, low sulphur prices and high natural gas prices, a significant element of cost in sulphur mining, caused our Main Pass sulphur mining operations to be uneconomical. As a result, in July 2000, we announced our plan to discontinue our sulphur mining operations. Production from the Main Pass sulphur mine ceased on August 31, 2000. We then initiated a plan to sell our sulphur transportation and terminaling assets.

Sale of Sulphur Assets. In June 2002, we sold our sulphur transportation and terminaling assets to Gulf Sulphur Services Ltd, LLP, a sulphur services joint venture owned by Savage Industries Inc. and IMC Global Inc. In connection with this transaction, we also settled all our disputes with IMC Global and its subsidiaries with respect to our long-term sulphur supply contract. We also agreed to indemnification obligations with respect to the sulphur assets sold to the joint venture, including certain environmental issues and liabilities relating to historical sulphur operations engaged in by us and our predecessor companies. In addition, we agreed to assume from IMC Global and indemnify it against any subsequent obligations, including environmental obligations, other than liabilities existing as of the closing of the sale, associated with historical oil and gas operations undertaken by the Freeport-McMoRan companies prior to the 1997 merger of Freeport-McMoRan Inc. and IMC Global. See "Risk Factors" below.

Sulphur Assets. Our primary remaining sulphur asset is our Port Sulphur facility, which is a combined liquid storage tank farm and stockpile area. The Port Sulphur terminal is currently inactive because it primarily served the Main Pass sulphur mine, which ceased operations in August 2000. The Port Sulphur terminal is being marketed and may be converted for use by other industries.

Sulphur Reclamation Obligations. We must restore our sulphur mines and related facilities to a condition that complies with environmental and other regulations. The reclamation obligations relating to our sulphur mines and related facilities were fully accrued at December 31, 2002. See "Critical Accounting Policies and Estimates" included in Items 7. and 7A. of this Form 10-K for a discussion of a new accounting standard, effective January 1, 2003, requiring a change in the accounting for reclamation costs. For financial information about our estimated future reclamation costs, including those relating to Main Pass and the transactions with Offshore Specialty Fabricators Inc. (OSFI), see "Discontinued Operations" and "Environmental" in Items 7. and 7A. and Note 7 of in this Form 10-K.

Our Freeport Energy subsidiary has assumed responsibility for environmental liabilities associated with the prior operations of its predecessors, including reclamation responsibilities at two previously producing sulphur mines, Caminada and Grand Ecaille. Sulphur production was suspended at the Caminada offshore sulphur mine in 1994. In February 2002, we reached an agreement with OSFI to handle the reclamation and removal of the Caminada mine and related facilities. The Caminada reclamation work was performed during 2002. For a summary of our agreements with OSFI, see "Discontinued Operations- Sulphur Reclamation Obligations" in Items 7. and 7A., and Note 7 of this Form 10-K.

Freeport Energy's Grande Ecaille mine, which was depleted in 1978, has been reclaimed in accordance with applicable regulations. Subsequently, we have undertaken to reclaim wellheads and other materials exposed through coastal erosion. We anticipate that additional expenditures for the reclamation activities will continue for an indeterminate period. Expenditures related to the Grande Ecaille mine during the past two years have totaled less than $0.1 million and are not expected to be significant during the next several years.

Freeport Energy has closed and reclaimed ten other sulphur mines, including the 1997 reclamation of the Grand Isle mine completed as part of the State of Louisiana's "rigs-to-reef" program. We believe that the reclamation efforts associated with these previously closed sulphur mines complied with the applicable regulations in existence at the time the mines were closed and with customary industry practices. However, we cannot assure you that we will not incur reclamation costs materially greater than those we anticipate or that the timing of these costs will occur as we presently estimate.

REGULATION

General. Our exploration, development and production activities are subject to federal, state and local laws and regulations governing exploration, development, production, environmental matters, occupational health and safety, taxes, labor standards and other matters. All material licenses, permits and other authorizations currently required for our operations have been obtained or timely applied for. Compliance is often burdensome, and failure to comply carries substantial penalties. The heavy and increasing regulatory burden on the oil and gas industry increases the cost of doing business and consequently affects profitability. See "Risk Factors" below.

Exploration, Production and Development. Our exploration, production and development operations are subject to regulations at both the federal and state levels. Regulations require operators to obtain permits to drill wells and to meet bonding and insurance requirements in order to drill, own or operate wells. Regulations also control the location of wells, the method of drilling and casing wells, the restoration of properties upon which wells are drilled and the plugging and abandoning of wells. Our oil and gas operations are also subject to various conservation laws and regulations, which regulate the size of drilling units, the number of wells that may be drilled in a given area, the levels of production, and the unitization or pooling of oil and gas properties.

Federal leases. At December 31, 2003, we had interests in 18 offshore leases located in federal waters on the Gulf of Mexico's outer continental shelf. Federal offshore leases are administered by the MMS. These leases were issued through competitive bidding, contain relatively standard terms and require compliance with detailed MMS regulations and the Outer Continental Shelf Lands Act, which are subject to interpretation and change by the MMS. Lessees must obtain MMS approval for exploration, development and production plans prior to the commencement of offshore operations. In addition, approvals and permits are required from other agencies such as the U.S. Coast Guard, the Army Corps of Engineers and the Environmental Protection Agency. The MMS has promulgated regulations requiring offshore production facilities and pipelines located on the outer continental shelf to meet stringent engineering and construction specifications, and has proposed and/or promulgated additional safety-related regulations concerning the design and operating procedures of these facilities and pipelines. MMS regulations also restrict the flaring or venting of natural gas, and proposed regulations would prohibit the flaring of liquid hydrocarbons and oil without prior authorization.

The MMS has promulgated regulations governing the plugging and abandonment of wells located offshore and the installation and removal of all production facilities. The MMS generally requires that lessees have substantial net worth or post supplemental bonds or other acceptable assurances that the obligations will be met. The cost of these bonds or other surety can be substantial, and there is no assurance that supplemental bonds or other surety can be obtained in all cases. With regard to the MMS supplemental bonding requirements, we currently have a trust agreement with the MMS that requires us to provide the MMS certain financial assurances for the reclamation obligations associated with Main Pass. We continue to work cooperatively with the MMS and expect to satisfy these requirements by providing financial assurances from MOXY. In addition, if requested by us, K1 USA will provide credit support to cover up to $10 million of MMS bonding requirements covering the Main Pass oil assets now owned by K-Mc I. We and our subsidiaries' ongoing compliance with applicable MMS requirements will be subject to meeting certain financial and other criteria. Under some circumstances, the MMS could require any of our operations on federal leases to be suspended or terminated. Any suspension or termination of our operations could have a material adverse affect on our financial condition and results of operations.

State and Local Regulation of Drilling and Production. We own interests in properties located in state waters of the Gulf of Mexico offshore Texas and Louisiana. These states regulate drilling and operating activities by requiring, among other things, drilling permits and bonds and reports concerning operations. The laws of these states also govern a number of environmental and conservation matters, including the handling and disposing of waste materials, unitization and pooling of natural gas and oil properties, and the levels of production from natural gas and oil wells.

Environmental Matters. Our operations are subject to numerous laws relating to environmental protection. These laws impose substantial liabilities for any pollution resulting from our operations. We believe that our operations substantially comply with applicable environmental laws. See "Risk Factors" below.

Solid Waste. Our operations require the disposal of both hazardous and nonhazardous solid wastes that are subject to the requirements of the Federal Resource Conservation and Recovery Act and comparable state statutes. In addition, the EPA and certain states in which we currently operate are presently in the process of developing stricter disposal standards for nonhazardous waste. Changes in these standards may result in our incurring additional expenditures or operating expenses.

Hazardous Substances. The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), also known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on some classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include but are not limited to the owner or operator of the site or sites where the release occurred, or was threatened and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Persons responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances and for damages to natural resources. Despite the "petroleum exclusion" of CERCLA that encompasses wastes directly associated with crude oil and gas production, we may generate or arrange for the disposal of "hazardous substances" within the meaning of CERCLA or comparable state statutes in the course of our ordinary operations. Thus, we may be responsible under CERCLA (or the state equivalents) for costs required to clean up sites where the release of a "hazardous substance" has occurred. Also, it is not uncommon for neighboring landowners and other third parties to file claims for cleanup costs as well as personal injury and property damage allegedly caused by the hazardous substances released into the environment. Thus, we may be subject to cost recovery and to some other claims as a result of our operations.

Air. Our operations are also subject to regulation of air emissions under the Clean Air Act, comparable state and local requirements and the Outer Continental Shelf Lands Act. The scheduled implementation of these laws could lead to the imposition of new air pollution control requirements on our operations. Therefore, we may incur capital expenditures over the next several years to upgrade our air pollution control equipment. We do not believe that our operations would be materially affected by these requirements, nor do we expect the requirements to be any more burdensome to us than to other companies our size involved in exploration and production activities.

Water. The Clean Water Act prohibits any discharge into waters of the United States except in strict conformance with permits issued by federal and state agencies. Failure to comply with the ongoing requirements of these laws or inadequate cooperation during a spill event may subject a responsible party to civil or criminal enforcement actions. Similarly, the Oil Pollution Act of 1990 imposes liability on "responsible parties" for the discharge or substantial threat of discharge of oil into navigable waters or adjoining shorelines. A "responsible party" includes the owner or operator of a facility or vessel, or the lessee or permittee of the area in which an offshore facility is located. The Oil Pollution Act assigns liability to each responsible party for oil removal costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct, or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Even if applicable, the liability limits for offshore facilities require the responsible party to pay all removal costs, plus up to $75 million in other damages. Few defenses exist to the liability imposed by the Oil Pollution Act.

The Oil Pollution Act also requires a responsible party to submit proof of its financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill. As amended by the Coast Guard Authorization Act of 1996, the Oil Pollution Act requires parties responsible for offshore facilities to provide financial assurance in amounts that vary from $35 million to $150 million depending on a company's calculation of its "worst case" oil spill. Both Freeport Energy and MOXY currently have insurance to cover its facilities' "worst case" oil spill under the Oil Pollution Act regulations. Thus, we believe that we are in compliance with this act in this regard.

Endangered Species. Several federal laws impose regulations designed to ensure that endangered or threatened plant and animal species are not jeopardized and their critical habitats are neither destroyed nor modified by federal action. These laws may restrict our exploration, development, and production operations and impose civil or criminal penalties for noncompliance.

Safety and Health Regulations. We are also subject to laws and regulations concerning occupational safety and health. We do not currently anticipate making substantial expenditures because of occupational safety and health laws and regulations. We cannot predict how or when these laws may be changed, nor the ultimate cost of compliance with any future changes. However, we do not believe that any action taken will affect us in a way that materially differs from the way it would affect other companies in our industry.

EMPLOYEES

At December 31, 2003, we had 19 employees located at our New Orleans, Louisiana headquarters, who are primarily devoted to managerial, marketing, land and geological functions. Our employees are not represented by any union or covered by any collective bargaining agreement. We believe our relations with our employees are satisfactory.

Since January 1, 1996, numerous services necessary for our business and operations, including certain executive, technical, administrative, accounting, financial, tax and other services, have been performed by FM Services Company pursuant to a services agreement. We owned 50 percent of FM Services through September 30, 2002, when we sold our interest to Freeport-McMoRan Copper & Gold Inc. for $1.3 million. FM Services continues to provide services to us on a contractual basis. We may terminate the services agreement at any time upon 90 days notice. For the year ended December 31, 2003, we incurred $3.3 million of expenses under the services agreement compared with $2.2 million in 2002 and $10.6 million in 2001. The decrease from 2001 reflects the reduced scope of our operations from the dispositions of oil and gas properties and our exit from the sulphur business, as well as the effect of the two Co-Chairmen of our Board agreeing not to receive any cash compensation during 2003 and 2002 (Note 8). We expect our costs under the FM Services contract to approximate $2.8 million in 2004.

We also use contract personnel to perform various professional and technical services, including but not limited to construction, well site surveillance, environmental assessment, and field and on-site production operating services. These services, which are intended to minimize our development and operating costs, allow our management staff to focus on directing all our oil and gas operations.

RISK FACTORS

This report includes "forward looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, including statements about our plans, strategies, expectations, assumptions and prospects. "Forward-looking statements" are all statements other than statements of historical fact, such as: statements regarding our business plan for 2004 and our financial plans our exploration plans and the potential development of the Main Pass Energy Hub™ Project; our ability to satisfy the MMS reclamation obligations with respect to Main Pass and our environmental obligations; drilling potential and results; anticipated flow rates of producing wells; anticipated initial flow rates of new wells; reserve estimates and depletion rates; general economic and business conditions; risks and hazards inherent in the production of oil and natural gas; demand and potential demand for oil and gas; trends in oil and gas prices; amounts and timing of capital expenditures and reclamation costs; and our ability to obtain necessary permits for new operations.

Forward-looking statements are based on assumptions and analyses made in light of our experience and perception of historical trends, current conditions, expected future developments and other factors we believe are appropriate under the circumstances. These statements are subject to a number of assumptions, risks and uncertainties, including the risk factors discussed below and in our other filings with the SEC, general economic and business conditions, the business opportunities that may be presented to and pursued by us, changes in laws and other factors, many of which are beyond our control. Except for our ongoing obligations under federal securities laws, we do not intend, and we undertake no obligation, to update or revise any forward-looking statements. Readers are cautioned that forward-looking statements are not guarantees of future performance and actual results and developments may differ materially from those projected in the forward-looking statements. Important factors that could cause actual results to differ materially from our expectations include, among others, the following:

Factors Relating to Financial Matters

We will require additional capital to fund our future drilling activities. If we fail to obtain additional capital, we may not be able to continue our operations. Historically, we have funded our operations and capital expenditures through:

- our cash flow from operations;
- entering into exploration arrangements with other parties;
- selling oil and gas properties;
- borrowing money from banks; and
- selling preferred and common stock and securities convertible into common stock.

In the near term, we plan to continue to aggressively pursue the exploratory drilling activities. We anticipate participating in the drilling of 10-12 wells during the next twelve months with estimated aggregate costs of $40-$50 million net to our planned interests. In addition, we may have funding requirements under the El Paso program, if and when interests in those properties revert to us. We have also been evaluating alternative uses of our discontinued sulphur facilities at Main Pass. We intend to fund these near-term expenditures with the proceeds we received from our convertible debt offering in July 2003. However, our resources may prove to be insufficient for these working capital and capital expenditure requirements even if we are successful in our exploration activities. In order to complete our business plan, over the longer term we expect we will need to raise additional funds through public or private equity or debt financing. If we fail to obtain additional capital, we may not be able to continue our operations.

Our future revenues will be reduced as a result of agreements that we have entered into and may enter into in the future. We have entered into agreements with third parties in order to fund the exploration and development of certain of our properties. These agreements will reduce our future revenues. For example, we have entered into a farm-out agreement with El Paso to fund the exploration and development for four of our prospects, two of which resulted in discoveries requiring further delineation and two of which were nonproductive. We have also entered into a multi-year joint venture agreement with a private exploration and production company, who will participate for 40 percent of our interest in prospects outside the JB Mountain and Mound Point areas. We may also seek to enter into additional farm-out or other arrangements with other companies. Such arrangements will reduce our share of future revenues associated with our exploration prospects, and, in the case of the El Paso farm-out arrangement, will defer the realization of the value of our interest in the prospects until specified production quantities have been achieved or specified net production proceeds have been received for the benefit of the other party. Consequently, even if exploration and development of the prospects is successful, we cannot assure you that such exploration and development will result in an increase in our proved oil and gas reserves or when such an increase might occur.

In addition to farm-outs and similar arrangements, we may consider sales of interests in our properties, which in the case of producing properties would reduce future revenues, and in the case of exploration properties would reduce our prospects.

We have incurred losses from our operations in the past and our failure to achieve profitability in the future could adversely affect the trading price of our common stock. During 2002, our oil and gas operations achieved operating income of $17.9 million, which included $44.1 million of gains on the disposition of oil and gas property interests. However, our oil and gas operations incurred losses of $27.5 million in 2003, $104.8 million in 2001, $34.9 million in 2000, $2.8 million in 1999 and $17.6 million in 1998. No assurance can be given that we will achieve profitability or positive cash flows from our operations in the future. Our failure to achieve profitability in the future could adversely affect the trading price of our common stock and convertible preferred stock and our ability to continue as a going concern.

We are responsible for reclamation, environmental and other obligations relating to our former sulphur operations, including Main Pass. In December 1997, we assumed responsibility for potential liabilities, including environmental liabilities, associated with the prior conduct of the businesses of our predecessors. Among these are potential liabilities arising from sulphur mines that were depleted and closed in the past in accordance with environmental laws in effect at the time, particularly in coastal or marshland areas that have experienced subsidence or erosion that has exposed previously buried pipelines and equipment. New laws or actions by governmental agencies calling for additional reclamation costs on those closed operations could result in significant additional reclamation costs for us. We could also be subject to potential liability for personal injury or property damage relating to wellheads and other materials at closed mines in coastal areas that have become exposed through coastal erosion. As of December 31, 2003, we had accrued $14.0 million relating to reclamation liabilities with respect to our discontinued sulphur operations. We cannot assure you that our current and future accruals for reclamation costs will be sufficient to fully cover these costs, that we will have the cash to fund these costs when incurred or that we will be able to satisfy the governmental bonding requirements.

We are subject to indemnification obligations with respect to the sulphur transportation and terminaling assets that we sold in June 2002, including obligations arising under environmental laws. We are also subject to indemnification obligations with respect to the sulphur operations previously engaged in by us or our predecessor companies. In addition, we assumed, and agreed to indemnify IMC Global from, certain potential obligations, including environmental obligations, of IMC Global relating to historical oil and gas operations conducted by the Freeport-McMoRan companies prior to the merger of Freeport-McMoRan Inc. and IMC Global. Our liabilities with respect to these obligations could adversely affect our operations and liquidity. For more information regarding these obligations, see "Discontinued Sulphur Operations – Sale of Sulphur Assets" above.

Factors Relating to Our Operations

Our future performance depends on our ability to add reserves. Our future financial performance depends in large part on our ability to find, develop and produce oil and gas reserves. We cannot assure you that we will be able to do so on a profitable basis. Moreover, because an ownership interest in prospects subject to a farm-out or other exploration arrangement will revert to us only upon the achievement of a specified production threshold or the receipt of specified net production proceeds, significant discoveries on these prospects will be needed to increase our proved oil and gas reserves. We cannot assure you that any of our exploration or farm-out arrangements will result in an increase in our proved oil and gas reserves, or if they do result in an increase, when that might occur.

Our exploration and development activities may not be commercially successful. Oil and gas exploration and development involve a high degree of risk that hydrocarbons will not be found, that they will not be found in commercial quantities, or that the value produced will be less than drilling, completion and operating costs. The 3-D seismic data and other technologies that we use do not allow us to know conclusively prior to drilling a well that oil or gas is present or economically producible. The cost of drilling, completing and operating a well is often uncertain, especially when drilling offshore, and cost factors can adversely affect the economics of a project. Our drilling operations may be changed, delayed or canceled as a result of numerous factors, including:

- the market price of oil and gas;
- unexpected drilling conditions;

- unexpected pressure or irregularities in formations;
- equipment failures or accidents;
- title problems;
- hurricanes, which are common in the Gulf of Mexico during certain times of the year, and other adverse weather conditions;
- regulatory requirements; and
- unavailability or high cost of equipment or labor.

Further, completion of a well does not guarantee that it will be profitable or even that it will result in recovery of drilling, completion and operating costs.

In addition, we plan to conduct most of our near-term exploration, development and production operations on the deep shelf of the Gulf of Mexico, an area that has had limited historical drilling activity due, in part, to its geologic complexity. There are additional risks associated with deep shelf drilling (versus traditional shelf drilling) that could result in substantial losses. Deeper targets are more difficult to detect with traditional seismic processing. For example, two of four initial exploratory wells drilled at deep shelf prospects subject to the El Paso farm-out arrangement were unsuccessful and were plugged and abandoned. Moreover, drilling expense and the risk of mechanical failure is significantly higher because of the additional depth and adverse conditions such as high temperature and pressure. Our experience suggests that exploratory costs can sometimes exceed $30 million per deep shelf well drilled. Accordingly, we cannot assure you that our oil and gas exploration activities, either on the deep shelf or elsewhere, will be commercially successful. Additionally, while the MMS has proposed certain royalty suspension incentives related to drilling on the deep shelf, such incentives may not become effective and, even if effective, may not benefit us.

The future results of our oil and gas business are difficult to forecast, primarily because the results of our exploration strategy are unpredictable. Most of our oil and gas business is devoted to exploration, the results of which are unpredictable. In addition, we use the successful efforts accounting method for our oil and gas exploration and development activities. This method requires us to expense geological and geophysical costs and the costs of unsuccessful exploration wells as they occur, rather than capitalizing these costs up to a specified limit as required by the full cost accounting method. Because the timing difference between incurring exploration costs and realizing revenues from successful properties can be significant, losses may be reported even though exploration activities may be successful during a reporting period. Accordingly, depending on our exploration results, we may incur significant losses as we continue to pursue our exploration activities. We cannot assure you that our oil and gas operations will achieve or sustain positive earnings or cash flows from operations in the future.

The marketability of our production depends mostly upon the availability, proximity and capacity of gas gathering systems, pipelines and processing facilities. The marketability of our production depends on the availability, operation and capacity of gas gathering systems, pipelines and processing facilities. If such systems and facilities are unavailable or lack available capacity, we could be forced to shut in producing wells or delay or discontinue development plans. Federal and state regulation of oil and gas production and transportation, general economic conditions and changes in supply and demand could adversely affect our ability to produce and market our oil and natural gas. If market factors change dramatically, the financial impact on us could be substantial. The availability of markets and the volatility of product prices are beyond our control.

Because much of our reserves and production are concentrated in a small number of offshore properties, production problems or significant changes in reserve estimates related to any property could have a material impact on our business. Our current reserves and production primarily come from five producing properties in the shallow waters of the Gulf of Mexico. If mechanical problems, storms or other events reduced a substantial portion of this production, our cash flows would be adversely affected. If the actual reserves associated with our fields are less than our estimated reserves, our results of operations and financial condition could be adversely affected.

We are vulnerable to risks associated with the Gulf of Mexico because we currently explore and produce exclusively in that area. Our strategy of concentrating on the Gulf of Mexico makes us more vulnerable to the risks associated with operating in that area than our competitors with more geographically diverse operations. These risks include:

- hurricanes, which are common in the Gulf of Mexico during certain times of the year, and other adverse weather conditions;

- difficulties securing oil field services; and

- compliance with regulations.

In addition, production from the Gulf of Mexico generally declines more rapidly than in many other producing regions of the world. This results in recovery of a relatively higher percentage of reserves during the initial years of production, and a corresponding need to replace these reserves with discoveries at new prospects at a rapid rate.

The amount of oil and gas that we produce and the net cash flow that we receive from that production may differ materially from the amounts reflected in our reserve estimates. Our estimates of proved oil and gas reserves are based on reserve engineering estimates using guidelines established by the SEC. Reserve engineering is a subjective process of estimating recoveries from underground accumulations of oil and gas that cannot be measured in an exact manner. The accuracy of any reserve estimate depends on the quality of available data and the application of engineering and geological interpretation and judgment. Estimates of economically recoverable reserves and future net cash flows depend on a number of variable factors and assumptions, such as:

- historical production from the area compared with production from other producing areas;

- assumptions concerning future oil and gas prices, future operating and development costs, workover, remediation and abandonment costs, and severance and excise taxes; and

- the assumed effects of government regulation.

These factors and assumptions are difficult to predict and may vary considerably from actual results. In addition, different reserve engineers may make different estimates of reserve quantities and cash flows based on varying interpretations of the same available data. Also, estimates of proved reserves for wells with limited or no production history are less reliable than those based on actual production. Subsequent evaluation of the same reserves may result in variations, which may be substantial, in our estimated reserves. As a result, all reserve estimates are imprecise.

You should not construe the estimated present values of future net cash flows from proved oil and gas reserves as the current market value of our estimated proved oil and gas reserves. As required by the SEC, we have estimated the discounted future net cash flows from proved reserves based on the prices and costs prevailing at December 31, 2003, without any adjustment to normalize those prices and costs based on variations over time either before or after that date. Future prices and costs may be materially higher or lower. Future net cash flows also will be affected by such factors as:

- the actual amount and timing of production;

- changes in consumption by gas purchasers; and

- changes in governmental regulations or taxation.

In addition, we have used a 10 percent discount factor, which the SEC requires all companies to use to calculate discounted future net cash flows for reporting purposes. That is not necessarily the most appropriate discount factor to be used in determining market value, since interest rates vary from time to time, and the risks associated with operating particular oil and gas properties can vary significantly.

Financial difficulties encountered by our partners or third-party operators could adversely affect the exploration and development of our prospects. We have a farm-out agreement with El Paso to fund the exploration and development costs of our JB Mountain and Mound Point prospects. We have also entered into a multi-year joint venture exploration arrangement with a private exploration and production company that has committed to fund a minimum of $200 million for its share of the costs associated with other exploration prospects. In addition, other companies operate some of the other properties in which we have an ownership interest. Liquidity and cash flow problems encountered by our partners or the co-owners of our properties may prevent or delay the drilling of a well or the development of a project.

In addition, our farm-out partners and working interest co-owners may be unwilling or unable to pay their share of the costs of projects as they become due. In the case of a farm-out partner, we would have to obtain alternative funding in order to complete the exploration and development of the prospects subject to the farm-out agreement. In the case of a working interest owner, we could be required to pay the working interest owner's share of the project costs. We cannot assure you that we would be able to obtain the capital necessary to fund either of these contingencies.

We cannot control the activities on properties we do not operate. Other companies operate some of the properties in which we have an interest. As a result, we have a limited ability to exercise influence over the operation of these properties or their associated costs. The success and timing of our drilling and development activities on properties operated by others therefore depend upon a number of factors outside of our control, including:

- timing and amount of capital expenditures;
- the operator's expertise and financial resources;
- approval of other participants in drilling wells; and
- selection of technology.

Our revenues, profits and growth rates may vary significantly with fluctuations in the market prices of oil and gas. In recent years, oil and gas prices have fluctuated widely. We have no control over the factors affecting prices, which include:

- the market forces of supply and demand;
- regulatory and political actions of domestic and foreign governments; and
- attempts of international cartels to control or influence prices.

Any significant or extended decline in oil and gas prices would have a material adverse effect on our profitability, financial condition and operations and on the trading prices of our securities.

If oil and gas prices decrease or our exploration efforts are unsuccessful, we may be required to write down the capitalized cost of individual oil and gas properties. This could occur when oil and gas prices are low or if we have substantial downward adjustments to our estimated proved oil and gas reserves, increases in our estimates of development costs or nonproductive exploratory drilling results. A writedown could adversely affect the prices of our securities.

We use the successful efforts accounting method. All property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending the determination of whether proved reserves are discovered. If proved reserves are not discovered with an exploratory well, the costs of drilling the well are expensed. All geological and geophysical costs on exploratory prospects are expensed as incurred.

The capitalized costs of our oil and gas properties, on a field-by-field basis, may exceed the estimated future net cash flows of that field. If so, we record impairment charges to reduce the capitalized costs of each such field to our estimate of the field's fair market value. Unproved properties are evaluated at the lower of cost or fair market value. These types of charges will reduce our earnings and stockholders' equity.

We assess our properties for impairment periodically, based on future estimates of proved and risk-adjusted probable reserves, oil and gas prices, production rates and operating, development and reclamation costs based on operating budget forecasts. Once incurred, an impairment charge is not reversible at a later date even if oil and gas prices increase or our estimated proved reserves increase.

Shortages of supplies, equipment and personnel may adversely affect our operations. Our ability to conduct operations in a timely and cost effective manner depends on the availability of supplies, equipment and personnel. The offshore oil and gas industry is cyclical and experiences periodic shortages of drilling rigs, work boats, tubular goods, supplies and experienced personnel. Shortages can delay operations and materially increase operating and capital costs.

The loss of key personnel could adversely affect our ability to operate. We depend, and will continue to depend in the foreseeable future, on the services of key employees with extensive experience and expertise in:

- evaluating and analyzing producing oil and gas properties and drilling prospects;
- maximizing production from oil and gas properties; and
- marketing oil and gas production.

Our ability to retain key employees is important to our future success and growth. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on our business.

The oil and gas exploration business is very competitive, and most of our competitors are much larger and financially stronger than we are. The business of oil and gas exploration, development and production is intensely competitive, and we compete with many companies that have significantly greater financial and other resources than we have. Our competitors include the major integrated oil companies and a substantial number of independent exploration companies. We compete with these companies for supplies, equipment, labor and prospects. These competitors may, for example, be better able to:

- access less expensive sources of capital;
- obtain equipment, supplies and labor on better terms;
- develop, or buy, and implement new technologies; and
- access more information relating to prospects.

Offshore operations are hazardous, and the hazards are not fully insurable. Our operations are subject to the hazards and risks inherent in drilling for, producing and transporting oil and gas. These hazards and risks include:

- fires;
- natural disasters;
- abnormal pressures in formations;
- blowouts;
- cratering;
- pipeline ruptures; and
- spills.

If any of these or similar events occur, we could incur substantial losses as a result of death, personal injury, property damage, pollution and lost production. Moreover, our drilling, production and transportation operations in the Gulf of Mexico are subject to operating risks peculiar to the marine environment. These risks include:

- hurricanes, which are common in the Gulf of Mexico during certain times of the year, and other adverse weather conditions;
- more extensive governmental regulation (including regulations that may, in certain circumstances, impose strict liability for pollution damage); and
- interruption or termination of operations by governmental authorities based on environmental, safety or other considerations.

Our liability, property damage, business interruption and other insurance coverages do not provide protection against all potential liabilities incident to the ordinary conduct of our business and do not provide coverage for damages caused by war or, in certain circumstances, acts of terrorism. Moreover, our insurance program is subject to coverage limits, deductibles and other conditions. The occurrence of an event that is not fully covered by insurance could adversely affect our financial condition and results of operations.

Hedging our production may result in losses. We may enter arrangements to reduce our exposure to fluctuations in the market prices of oil and natural gas. We may enter into oil and gas hedging contracts in order to increase credit availability. Hedging will expose us to risk of financial loss in some circumstances, including if

- production is less than expected;
- the other party to the contract defaults on its obligations; or
- there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

In addition, hedging may limit the benefit we would otherwise receive from increases in the prices of oil and gas. Further, if we do not engage in hedging, we may be more adversely affected by changes in oil and gas prices than our competitors who engage in hedging.

Compliance with environmental and other government regulations could be costly and could negatively affect production. Our operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may:

- require the acquisition of a permit before drilling commences;
- restrict the types, quantities and concentration of various substances that can be released into the environment from drilling and production activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas;
- require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells; and
- impose substantial liabilities for pollution resulting from our operations.

The recent trend toward stricter standards in environmental legislation and regulations is likely to continue and could have a significant impact on our operating costs, as well as on the oil and gas industry in general.

Our operations could result in liability for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. We could also be liable for environmental damages caused by previous property owners. As a result, substantial liabilities to third parties or governmental entities may be incurred which could have a material adverse affect on our financial condition and results of operations. We maintain insurance coverage for our operations, including limited coverage for sudden and accidental environmental damages, but we do not believe that coverage for environmental damages that occur over time or complete coverage for sudden and accidental environmental damages is available at a reasonable cost. Accordingly, we could be subject to liability or lose the right to continue exploration or production activities on some or all of our properties if certain environmental damages occur.

The Oil Pollution Act of 1990 imposes a variety of legal requirements on "responsible parties" related to the prevention of oil spills. The implementation of new, or the modification of existing, environmental laws or regulations, including regulations promulgated pursuant to the Oil Pollution Act of 1990, could have a material adverse effect on us.

Factors Relating to the Potential Main Pass Energy Hub™ Project

We are continuing to assess the suitability of our discontinued Main Pass sulphur facilities as an LNG receipt and processing terminal. Even if it is technically feasible to retrofit the facilities for such use, we may not be able to obtain the necessary financing to complete the project. We are continuing to assess the feasibility of converting our Main Pass sulphur facilities to an LNG receipt and processing terminal. Even if feasible, conversion of the facilities would require significant project-based financing for the associated engineering, environmental, marine, regulatory, construction and legal costs. We may not be able to obtain such financing at an acceptable cost, or at all, which would have an adverse effect on our ability to pursue alternative uses of the Main Pass facilities. Financing arrangements for the project may also reduce our economic interest in, and control of, the project.

We may not be able to obtain the approvals and permits from regulatory agencies necessary to use our Main Pass facilities as an LNG terminal. The receipt and processing of LNG is highly regulated, and we must obtain several regulatory approvals and permits in order to develop the project. We estimate that it may take at least 12 months from the filing of the application in February 2004 to obtain the approvals and permits necessary to proceed with the construction and operation of such facilities. We have no control over the timing or outcome of the review and approval process.

Our interest in the proposed LNG terminal project will be reduced if K-Mc I exercises its option to acquire a passive equity interest in our Main Pass Energy Hub™ Project, and may be further reduced by any financing arrangements that may be entered into with respect to the project. In addition, an issue in litigation relates to whether OSFI would be entitled to participate in the project. In connection with our K1 business alliance, K1 USA has the option, exercisable upon the closing of any project financing arrangements, to acquire up to 15 percent of our equity interest in the Main Pass Energy Hub™ Project by agreeing prospectively to fund 15 percent of our future contributions to the project. If the option is exercised, our economic interest in Main Pass Energy Hub™ Project would be reduced. Financing arrangements for the project may also reduce our economic interest in, and control of, the project. In addition, an issue in litigation relates to whether OSFI would be entitled to participate in the project (see Item 3. "Legal Proceedings" of this Form 10-K).

Failure of LNG to compete successfully in the United States gas market could have a detrimental effect on our ability to pursue alternative uses of our Main Pass facilities. Because the United States historically has had an abundant supply of domestic natural gas, LNG has not been a major energy source. The failure of LNG to become a competitive supply alternative to domestic natural gas and other import alternatives may have a material adverse effect on our ability to use our Main Pass facilities as an LNG receipt, processing and distribution terminal.

If we were to develop an LNG terminal at our Main Pass facilities, fluctuations in energy prices or the supply of natural gas could be harmful to those operations. If the delivered cost of LNG is higher than the delivered costs of natural gas or natural gas derived from other sources, our proposed terminal's ability to compete with such supplies would be negatively affected. In addition, if the supply of LNG is limited or restricted for any reason, our ability to profitably operate an LNG terminal would be materially affected. The revenues generated by such a terminal would depend on the volume of LNG processed and the price of the natural gas produced, both of which can be affected by the price of natural gas and natural gas liquids.

Our proposed LNG terminal would be subject to significant operating hazards and uninsured risks, one or more of which may create significant liabilities for us. In the event we complete and establish a LNG terminal at Main Pass, the operations of such facility would be subject to the inherent risks associated with those operations, including explosions, pollution, fires, hurricanes and adverse weather conditions, and other hazards, any of which could result in damage to or destruction of our facilities or damage to persons and other property. In addition, these operations could face risks associated with terrorism. If any of these events were to occur, we could suffer substantial losses. Depending on commercial availability, we expect to maintain insurance against these types of risks to the extent and in the amounts that we believe are reasonable. Our financial condition and operations could be adversely affected if a significant event occurs that is not fully covered by insurance.

Other Factors

The U.S military intervention in Iraq, the terrorist attacks in the United States on September 11, 2001, and the potential for future terrorist acts have created economic, political and social uncertainties that could materially and adversely affect our business. It is possible that further acts of terrorism may be directed against the United States domestically or abroad, and such acts of terrorism could be directed against properties and personnel of companies such as ours. Those attacks, the potential for more terrorist acts, and the resulting economic, political and social uncertainties have caused our insurance premiums to increase significantly. Moreover, while our property and business interruption insurance currently covers damages to insured property directly caused by terrorism, this insurance does not cover damages and losses caused by war. Terrorism and war developments may materially and adversely affect our business and profitability and the prices of our securities in ways that we cannot predict.

Arthur Andersen LLP, our former auditors, audited certain financial information included in this Form 10-K. In the event such financial information is later determined to contain false or misleading statements, you may be unable to recover damages from Arthur Andersen LLP. Arthur Andersen LLP completed its audit of our financial statements for the year ended December 31, 2001, and issued its report with respect to such financial statements dated May 9, 2002 (except with regard to Note 10 as to which the date was June 7, 2002). In July 2002, our board of directors, at the recommendation of our audit committee, approved the appointment of Ernst & Young LLP as our independent public accountants to audit our financial statements for fiscal year 2002. Ernst & Young replaced Arthur Andersen, which had served as our independent auditors since 1994. Arthur Andersen audited the financial statements that we include in this Form 10-K as of December 31, 2001 and for the year ended December 31, 2001, as set forth in their reports herein.

In June 2002, Arthur Andersen was convicted of obstructing justice, a felony offense. The SEC prohibits firms convicted of a felony from auditing public companies. Arthur Andersen is thus unable to consent to the inclusion of its report covering McMoRan's 2001 financial statements with respect to this Form 10-K. Under these circumstances, Rule 437a under the Securities Act of 1933 (the "Securities Act") permits us to file this Form 10-K, which is incorporated by reference into registration statements we have on file with the SEC, without a written consent from Arthur Andersen. The Securities Act provides that if part of a registration statement at the time it becomes effective contains an untrue statement of a material fact, or omits a material fact required to be stated therein or necessary to make the statements therein not misleading, any person acquiring a security pursuant to such registration statement (unless it is proved that at the time of such acquisition such person knew of such untruth or omission) may assert a claim against, among others, an accountant who has consented to be named as having certified any part of the registration statement or as having prepared any report for use in connection with the registration statement. As a result, with respect to transactions in our securities pursuant to our registration statements that occur after this Form 10-K is filed with the SEC, Arthur Andersen will not have any liability under the Securities Act for any untrue statements of a material fact contained in the financial statements audited by Arthur Andersen or any omissions of a material fact required to be stated therein. Accordingly, you would be unable to assert a claim against Arthur Andersen under the Securities Act.

GLOSSARY

3-D seismic technology. Seismic data which has been digitally recorded, processed and analyzed in a manner that permits color enhanced three dimensional displays of geologic structures. Seismic data processed in that manner facilitates more comprehensive and accurate analysis of subsurface geology, including the potential presence of hydrocarbons.

Bbl or Barrel. One stock tank barrel, or 42 U.S. gallons liquid volume (used in reference to crude oil or other liquid hydrocarbons).

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil, condensate or natural gas liquids.

Block. A block depicted on the Outer Continental Shelf Leasing and Official Protraction Diagrams issued by the U.S. Mineral Management Service or a similar depiction on official protraction or similar diagrams issued by a state bordering on the Gulf of Mexico.

Completion. The installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

Developed acreage. Acreage in which there are one or more producing wells or shut-in wells capable of commercial production and/or acreage with established reserves in quantities we deemed sufficient to develop.

Development well. A well drilled into a proved natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

Exploratory well. A well drilled (1) to find and produce natural gas or oil reserves not classified as proved, (2) to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or (3) to extend a known reservoir.

Farm-in or farm-out. An agreement under which the owner of a working interest in a natural gas and oil lease assigns the working interest or a portion of the working interest to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells at its expense in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The agreement is a "farm-in" to the assignee and a "farm-out" to the assignor.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest and/or operating right is owned.

Gulf of Mexico shelf. The offshore area within the Gulf of Mexico seaward on the coastline extending out to 200 meters water depth.

MBbls. One thousand barrels, typically used to measure the volume of crude oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet, typically used to measure the volume of natural gas.

Mcfe. One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMBbls. One million barrels, typically used to measure the volume of crude oil or other liquid hydrocarbons.

MMcf. One million cubic feet, typically used to measure the volume of natural gas at specified temperature and pressure.

MMcfe. One million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMcfe/d. One million cubic feet equivalent per day.

MMS. The U.S. Minerals Management Service.

Net acres or net wells. Gross acres multiplied by the percentage working interest and/or operating right owned.

Net feet of pay. The thickness of reservoir rock estimated to both contain hydrocarbons and be capable of contributing to producing rates.

Net profit interest. An interest in profits realized through the sale of production, after costs. It is carved out of the working interest.

Net revenue interest. An interest in a revenue stream net of all other interests burdening that stream, such as a lessor's royalty and any overriding royalties. For example, if a lessor executes a lease with a one-eighth royalty, the lessor's net revenue interest is 12.5 percent and the lessee's net revenue interest is 87.5 percent.

Non-productive well. A well found to be incapable of producing hydrocarbons in quantities sufficient such that proceeds from the sale of production would exceed production expenses and taxes.

Overriding royalty interest. A revenue interest, created out of a working interest, that entitles its owner to a share of revenues, free of any operating or production costs. An overriding royalty is often retained by a lessee assigning an oil and gas lease.

Pay. Reservoir rock containing oil or gas.

Plant Products. Hydrocarbons (primarily ethane, propane, butane and natural gasolines) which have been extracted from wet natural gas and become liquid under various combinations of increasing pressure and lower temperature.

Productive well. A well that is found to be capable of producing hydrocarbons in quantities sufficient such that proceeds from the sale of production exceed production expenses and taxes.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved developed reserves. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. For additional information, see the SEC's definition in Regulation S-X Rule 4-10(a)(3).

Proved reserves. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. For additional information, see the SEC's definition in Regulation S-X Rule 4-10(a)(2).

Proved undeveloped reserves. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for production to occur. For additional information, see the SEC's definition in Regulation S-X Rule 4-10(a)(4).

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Sands. Sandstone or other sedimentary rocks.

SEC. Securities and Exchange Commission.

Sour. High sulphur content.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether the acreage contains proved reserves.

Working interest. The lessee's interest created by the execution of an oil and gas lease that gives the lessee the right to exploit the minerals on the property.

Item 3. Legal Proceedings

Daniel W. Krasner v. James R. Moffett; René L. Latiolais; J. Terrell Brown; Thomas D. Clark, Jr.; B.M. Rankin, Jr.; Richard C. Adkerson; Robert M. Wohleber; Freeport-McMoRan Sulphur Inc. and McMoRan Oil & Gas Co., Civ. Act. No. 16729-NC (Del. Ch. filed Oct. 22, 1998). Gregory J. Sheffield and Moise Katz v. Richard C. Adkerson, J. Terrell Brown, Thomas D. Clark, Jr., René L. Latiolais, James R. Moffett, B.M. Rankin, Jr., Robert M. Wohleber and McMoRan Exploration Co., (Court of Chancery of the State of Delaware, filed December 15, 1998.) These two lawsuits were consolidated in January 1999. The complaint alleges that Freeport-McMoRan Sulphur Inc.'s directors breached their fiduciary duty to Freeport-McMoRan Sulphur Inc.'s stockholders in connection with the combination of Freeport Sulphur and McMoRan Oil & Gas. The plaintiffs claim that the directors failed to take actions that were necessary to obtain the true value of Freeport Sulphur. The plaintiffs also claim that McMoRan Oil & Gas Co. knowingly aided and abetted the breaches of fiduciary duty committed by the other defendants. In January 2001, the court granted the defendants' motions to dismiss for the defendants with leave for the plaintiffs to amend. In February 2001, the plaintiffs filed an amended complaint, and the defendants then filed a motion to dismiss. In September 2002, the court granted the defendants' motion to dismiss. The plaintiffs appealed the court's decision and in June 2003, the Delaware Supreme Court reversed the trial court's dismissal and remanded the case to the trial court for further proceedings. The lawsuit is proceeding in the discovery stage at the trial level and McMoRan will continue to defend this action vigorously.

Freeport-McMoRan Sulphur LLC vs. Mike Mullen Energy Equipment Resources, Inc. and Offshore Specialty Fabricators, Inc., (United States District Court for the Eastern District of Louisiana, Case No. 03-1496; filed on May 27, 2003). This proceeding involves several matters. The most significant issue relates to whether Offshore Specialty Fabricators, Inc. ("OSFI") is entitled to participate in Freeport Sulphur ("FSC") redevelopment of the Main Pass sulphur assets for LNG and other purposes. A secondary issue relates to a dispute between FSC and Mullen regarding Mullen's failure to remove certain equipment from Main Pass, as well as Mullen's and OSFI's roles in the unauthorized removal of other equipment.

FSC and OSFI originally entered into a Turnkey Contract dated March 28, 2002, for the removal, site clearance and scrapping of Main Pass 299. The Turnkey Contract provided payment to OSFI for the Phase I work solely from two specific transactions which did not occur. OSFI would also share net revenues from any contingent interest FSC and OSFI maintained in any sale of the sulphur lease and Phase II facilities, but OSFI at its sole expense was responsible for removal of the Phase II sulphur facilities. See further description in Items 7. and 7A. "Discontinued Operations – Sulphur Reclamation Obligations." In the lawsuit, FSC alleges that OSFI failed to timely complete the Phase I reclamation under the Turnkey Contract and that OSFI delivered to Mullen, over FSC's objection, certain power plant equipment owned by FSC but in OSFI's possession. OSFI has counterclaimed against FSC for alleged breaches of the Turnkey Contract, claiming that it did in fact timely complete the Phase I reclamation and seeks recovery of $2.6 million plus contractual interest, attorney's fees and expenses, and confirmation of an equal share in any profitable use of the Phase II facilities. A trial date is set for May 2004, and McMoRan intends to vigorously pursue and defend this action.

Other than the proceeding discussed above, we may from time to time be involved in various legal proceedings of a character normally incident to the ordinary course of our business. We believe that potential liability from any of these pending or threatened proceedings will not have a material adverse effect on our financial condition or results of operations. We maintain liability insurance to cover some, but not all, of the potential liabilities normally incident to the ordinary course of our businesses as well as other insurance coverages customary in our business, with coverage limits as we deem prudent.

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

None.

Executive Officers of the Registrant

Listed below are the names and ages, as of March 1, 2004, of the present executive officers of McMoRan together with the principal positions and offices with McMoRan held by each.

Name	Age	Position or Office
James R. Moffett	65	Co-Chairman of the Board
Richard C. Adkerson	57	Co-Chairman of the Board
Glenn A. Kleinert	61	President and Chief Executive Officer
C. Howard Murrish	63	Executive Vice President
Nancy D. Parmelee	52	Senior Vice President, Chief Financial Officer and Secretary
Kathleen L. Quirk	40	Senior Vice President and Treasurer
John G. Amato	60	General Counsel

James R. Moffett has served as our Co-Chairman of the Board since November 1998. Mr. Moffett has also served as the Chairman of the Board of Freeport-McMoRan Copper & Gold Inc. (FCX) since May 1992, and as Chief Executive Officer of FCX from July 1995 to December 2003. Mr. Moffett's technical background is in geology and he has been actively engaged in petroleum geological activities in the areas of our company's operations throughout his business career. He is a founder of the predecessor of our company.

Richard C. Adkerson has served as our Co-Chairman of the Board since November 1998. He served as our President and Chief Executive Officer from November 1998 to February 2004. Mr. Adkerson has also served as Chief Executive Officer of FCX since December 2003, as President of FCX since April 1997 and as Chief Financial Officer from October 2000 until December 2003.

Glenn A. Kleinert has served as President and Chief Executive Officer since February 2004. Previously he served as Executive Vice President of McMoRan from May 2001 to February 2004. Mr. Kleinert has also served as President and Chief Operating Officer of MOXY since May 2001. Mr. Kleinert served as Senior Vice President of MOXY from November 1998 until May 2001. Mr. Kleinert served as Senior Vice President of McMoRan Oil & Gas Co. from September 1994 to November 1998.

C. Howard Murrish has served as Executive Vice President of McMoRan since November 1998. He served as Vice Chairman of the Board from May 2001 to February 2004. Mr. Murrish served as President and Chief Operating Officer of MOXY from September 1994 to May 2001.

Nancy D. Parmelee has served as Senior Vice President and Chief Financial Officer of McMoRan since August 1999 and Vice President and Controller - Accounting Operations from November 1998 through August 1999. She was appointed as Secretary of McMoRan in January 2000. Ms. Parmelee has served as Vice President and Controller - Operations of FCX since April 2003, and previously served as Assistant Controller of FCX from July 1994 to April 2003.

Kathleen L. Quirk has served as Senior Vice President and Treasurer of McMoRan since April 2002 and previously served as Vice President and Treasurer from January 2000 to April 2002. Ms. Quirk has served as Senior Vice President, Chief Financial Officer and Treasurer of FCX since December 2003, and previously served as Vice President and Treasurer from February 2000 to December 2003, and as Vice President from February 1999 to February 2000, and as Assistant Treasurer from November 1997 to February 1999. Ms. Quirk has served as Vice President and Treasurer of Freeport-McMoRan Energy LLC since April 2003 and previously served as Vice President from February 1999 to April 2003 and as Treasurer from November 1998 to February 1999.

John G. Amato has served as our General Counsel since November 1998. Mr. Amato also currently provides legal and business advisory services to FCX under a consulting arrangement.

PART II

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

Our common stock is listed on the New York Stock Exchange (NYSE) under the symbol "MMR." The following table sets forth, for the period indicated, the range of high and low sales prices, as reported by the NYSE.

	2003		2002	
	High	Low	High	Low
First Quarter	$12.20	$5.13	$6.35	$3.20
Second Quarter	13.20	9.60	4.50	3.35
Third Quarter	12.73	10.35	4.40	2.65
Fourth Quarter	20.00	10.39	5.40	2.54

As of March 1, 2004 there were approximately 8,700 holders of record of our common stock. We have not in the past paid, and do not anticipate in the future paying, cash dividends on our common stock. The decision whether or not to pay dividends and in what amounts is solely at the discretion of our Board of Directors.

Item 6. Selected Financial Data

The following table sets forth our selected audited historical financial and unaudited operating data for each of the five years in the period ended December 31, 2003. We became a publicly traded entity in November 1998, when McMoRan Oil & Gas Co. and Freeport-McMoRan Sulphur Inc. combined their operations. The information shown in the table below may not be indicative of our future results. You should read the information below together with Items 7. and 7A. "Management's Discussion and Analysis of Financial Condition and Results of Operations and Disclosures About Market Risks" and Item 8. "Financial Statements and Supplementary Data."

	2003	2002	2001	2000	1999
Financial Data	(Financial Data in thousands, except per share amounts)				
Years Ended December 31:					
Revenues	$ 16,114	$ 43,768	$ 72,972	$ 58,468	$ 54,344
Exploration expenses	14,109	13,259	61,831	53,975	6,411
Start-up costs for Main Pass Energy Hub™ Project	11,411[a]	-	-	-	-
Gain on sale of oil and gas properties	-	44,141[b]	-	43,212[b]	3,105
Operating income (loss)	(38,947)	17,942	(104,917)	920	(4,019)
Income (loss) from continuing operations	(41,847)	18,544	(104,801)	(34,859)	(2,804)
Income (loss) from discontinued operations	(11,233)[c]	(503)[c]	(43,260)[c]	(96,649)[c]	2,913
Cumulative effect of change in accounting principle	22,162[d]	-	-	-	-
Net income (loss) applicable to common stock	(32,656)	17,041	(148,061)	(131,508)	109
Basic net income (loss) per share of common stock:					
Continuing operations	(2.62)	1.09	(6.60)	(2.35)	(0.21)
Discontinued operations	(0.68)	(0.03)	(2.73)	(6.53)	0.22
Cumulative effect of change in accounting principle	1.33	-	-	-	-
Basic net income (loss) per share	(1.97)	1.06	(9.33)	(8.88)	0.01
Diluted net income (loss) per share of common stock:					
Continuing operations	(2.62)	0.93	(6.60)	(2.35)	(0.21)
Discontinued operations	(0.68)	(0.02)	(2.73)	(6.53)	0.22
Cumulative effect of change in accounting principle	1.33	-	-	-	-
Diluted net income (loss) per share	$ (1.97)	$ 0.91	$ (9.33)	$ (8.88)	$ 0.01
Average common shares outstanding					
Basic	16,602	16,010	15,869	14,806	13,385
Diluted	16,602	19,879[e]	15,869	14,806	13,385
At December 31:					
Working capital (deficit)	$ 83,143	$ 5,077	$ (88,145)	$ (50,024)	$ (3,108)
Property, plant and equipment, net	26,185	37,895	98,519	116,231	97,359
Discontinued sulphur business assets	312	355[f]	54,607	72,977	114,254
Total assets	169,280	72,448	189,686	299,324	301,281
Debt, including current portion	130,000	-	104,657	46,000	14,000
Mandatorily redeemable convertible preferred stock	30,586	33,773	-	-	-
Stockholders' equity (deficit)	(84,593)	$ (64,431)	$ (87,772)	$ 59,177	$ 155,071

a. Reflects costs associated with pursuit of the licensing, design and financing plans necessary to establish an energy hub at Main Pass Block 299 (Main Pass) in the Gulf of Mexico (Notes 3 and 4).

b. Includes sales of various oil and gas properties during 2002 (Note 4) and of Brazos Blocks A-19 and A-26 ($40.1 million) and Vermilion Block 408 ($3.1 million) during 2000.

c. The amount for 2003 includes a $5.9 million estimated loss on the pending disposal of our remaining sulphur railcars (Note 12). The amount for 2002 includes a $5.0 million gain on completion of the Caminada reclamation activities, a $5.2 million gain to adjust the estimated reclamation cost for certain Main Pass sulphur structures and facilities and a $4.0 million loss on the disposal of the sulphur transportation and terminaling assets (Note 7). The amount for 2001 includes $20.8 million charge to reduce the sulphur business assets to their net realizable value, $13.6 million to increase a recorded obligation for reimbursement of certain medical expenses (Note 11) and $10.0 million to reduce sulphur inventory to its then estimated fair value. Amounts during 2000 include charges totaling $86.0 million to reflect the cessation of the sulphur mining operation at Main Pass.
d. Reflects implementation of Statement of Financial Accounting Standard No. 143 "*Accounting for Asset Retirement Obligations*" effective January 1, 2003 (Note 1).
e. Includes the assumed conversion of McMoRan's 5% Convertible Preferred Stock into approximately 3.9 million shares (Notes 1 and 6).
f. Reflects sale of sulphur assets in June 2002 (Note 7).

	2003	2002	2001	2000	1999
Operating Data					
Sales Volumes:					
Gas (thousand cubic feet, or Mcf)	2,011,100	5,851,300[a]	11,136,800[a]	8,291,000	14,026,000
Oil, excluding Main Pass (barrels)	103,400	124,700[b]	342,800[b]	190,100	251,000
Oil from Main Pass (barrels)[c]	4,200	1,001,900	993,300	961,500	1,102,600
Plant products (equivalent barrels)[d]	20,700	26,100	81,100	-	-
Sulphur (long tons)	-	822,900	2,127,300	2,643,800	2,973,100
Average realization:					
Gas (per Mcf)	$ 5.64	$ 3.00	$ 3.59	$ 3.52	$ 2.30
Oil, excluding Main Pass (barrels)	31.03	24.24	24.62	30.66	17.85
Oil from Main Pass (barrels)	24.09	22.03	21.07	23.85	15.50
Sulphur (per long ton)	-	37.44	33.60	53.78	63.16

a. Sales volumes associated with the properties sold in February 2002 (Note 4) totaled 856,000 Mcf in 2002 and 3,200,000 Mcf in 2001.
b. Sales volumes associated with the properties sold in February 2002 totaled 18,500 barrels in 2002 and 147,300 barrels in 2001.
c. A joint venture acquired the Main Pass oil operations on December 16, 2002 (Note 4). Amounts during 2003 represent the sale of the remaining Main Pass product inventory.
d. During 2003 revenues included $0.8 million of proceeds associated with plant products (ethane, propane, butane, etc.). Revenues associated with plant products totaled $0.9 million in 2002 and $3.0 million in 2001.

Items 7. and 7A. Management's Discussion and Analysis of Financial Condition and Results of Operations and Disclosures About Market Risks

OVERVIEW

In management's discussion and analysis "we," "us," and "our" refer to McMoRan Exploration Co. and its consolidated subsidiaries, McMoRan Oil & Gas LLC ("MOXY") and Freeport-McMoRan Energy LLC ("Freeport Energy," formerly known as Freeport-McMoRan Sulphur LLC). You should read the following discussion in conjunction with our financial statements and the related discussion of "Business and Properties" included elsewhere in this Form 10-K. The results of operations reported and summarized below are not necessarily indicative of our future operating results. All subsequent references to Notes refer to Notes to Consolidated Financial Statements located in Item 8. "Financial Statements and Supplementary Data" elsewhere in this Form 10-K.

We engage in the exploration, development and production of oil and gas offshore in the Gulf of Mexico and onshore in the Gulf Coast region. We are also pursuing plans for the potential development of a liquefied natural gas (LNG) terminal at our former sulphur facilities at Main Pass Block 299 (Main Pass); we refer to this project as the Main Pass Energy Hub™ Project. We were previously engaged in the sulphur business until June 2002 (Note 7).

Background and Business Strategy

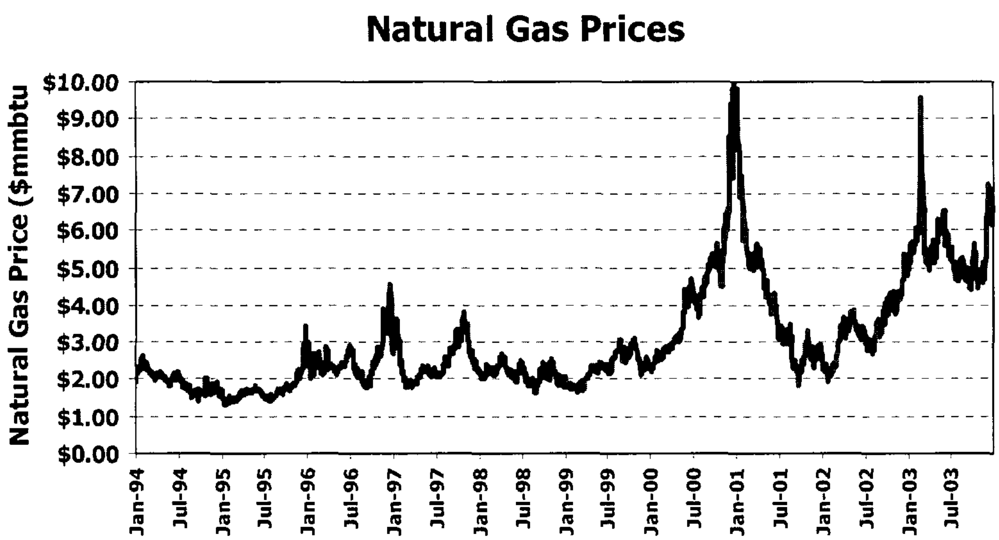
Our primary focus is on shallow-water "deep shelf" natural gas exploration and production opportunities. We consider the "deep shelf" to be geologic structures located in shallow waters of the Gulf of Mexico shelf at underground depths generally greater than 15,000 feet and lying below reservoirs know to have previously produced significant hydrocarbons. We believe that U.S. market conditions for natural gas have become increasingly attractive. Although the costs to drill deep wells are significant, we believe that the deep shelf provides attractive drilling opportunities because the shallow water depths and close proximity to existing oil and gas production infrastructure should allow discoveries to generate production and cash flows relatively quickly. Our near-term business strategy is to continue to pursue our exploration activities and our plans for the potential Main Pass Energy Hub™ Project.

In 2002 we faced significant financial liquidity issues as a result of adverse business conditions with our sulphur operations and significant nonproductive exploratory drilling costs. To address these issues, we exited the sulphur business in 2002 and repaid related debt with proceeds from the sale of our sulphur assets and with a portion of the proceeds raised in a $35 million preferred stock offering. During 2002, we also sold three of our producing oil and gas properties to repay debt and entered into a drilling arrangement to fund the drilling of four of our prospects, including federal lease OCS 310 ("JB Mountain") and Louisiana State Lease ("Mound Point"). During 2002 and 2003, we completed substantial dismantling and reclamation activities at our former offshore sulphur mine facilities and have made significant progress to resolve related regulatory compliance issues with the Minerals Management Service (MMS).

Our near-term business strategy will require significant capital during 2004 and 2005. We enhanced our overall financial flexibility during 2003 through the issuance of $130 million of convertible debt. In early 2004, we announced the formation of a multi-year exploration joint venture with a private exploration and production company that has committed to fund a minimum of $200 million for its share of exploration costs. Over the longer-term, we need to develop additional financial resources and secure financing for our operations through the discovery, development and production of oil and gas reserves, and once fully permitted and plans developed, for the construction and operation of the Main Pass Energy Hub™ Project or otherwise through other third-party financial arrangements. We believe our recent oil and gas exploration and development successes, together with the exploration potential of our remaining acreage position, and the sharing of exploration costs with our partners will enable us to achieve these goals. The ultimate outcome of our efforts is subject to various uncertainties, many of which are beyond our control. For additional information on these risk factors and others see "Risk Factors" in Items 1. and 2. "Business and Properties" included in this Form 10-K.

North American Natural Gas Environment

Economic growth in the U.S. over the past decade has resulted in increased energy consumption, with oil and natural gas making up a substantial portion of U.S. energy supplies. Natural gas is estimated to meet approximately one-fourth of current U.S. energy needs, and annual natural gas demand is generally anticipated to increase significantly from present levels of approximately 22 trillion cubic feet (Tcf) as a result of expected continued long-term overall U.S. economic growth, especially for electric power generation. Natural gas prices have increased significantly over the past two years as a result of these market conditions.



Virtually all U.S. natural gas supplies come from domestic reserves produced in onshore and offshore areas of the U.S. and Canada. However, production declines from existing natural gas reserves are not expected to be fully replaced by new reserve discoveries. As a result, new sources will be required to make up an increasingly greater share of U.S. natural gas supplies, including new supplies from Alaska, the Canadian Arctic, deep gas reservoirs in the offshore Gulf of Mexico and from imported LNG.

LNG imports historically have represented an insignificant natural gas supply source in the U.S. As a result, the U.S. currently has limited capabilities to receive and process LNG imports through four existing onshore LNG receiving terminals. Within the past year, numerous new LNG facilities have been proposed, most at onshore sites. Construction of such facilities often requires long lead times to secure regulatory and environmental permitting, as well as project financing. We believe that offshore locations for these facilities, such as the proposed Main Pass Energy Hub™ Project, could mitigate security, safety and environmental issues often faced by competing onshore facilities.

EXPLORATION ACTIVITIES

Drilling Update

We have identified 17 high-potential, high risk prospects outside the JB Mountain and Mound Point areas, most of which are deep gas targets near existing production infrastructure in the shallow waters of the Gulf of Mexico. We plan to participate in the drilling of 10 to 12 wells over the next twelve months, with an aggregate estimated cost ranging from $40 to $50 million, net to our planned interests. We are currently engaged in drilling the Dawson Deep prospect at Garden Banks Block 625 and we plan to commence drilling on three of these prospects during the first quarter of 2004, including the Lombardi Deep prospect at Vermilion Block 208, the Deep Tern Miocene prospect at Eugene Island Block 193, and the Phoenix prospect at Eugene Island Blocks 212/213. We are preparing plans to drill additional prospects.

In January 2004, we announced the formation of a multi-year exploration joint venture with a private exploration and production company, which has committed to fund a minimum of $200 million for its share of the joint venture's exploration costs. The new partner will participate for 40 percent of McMoRan's interests in prospects, located outside the JB Mountain and Mound Point areas. The first exploratory well included under this arrangement, Garden Banks Block 625 (Dawson Deep), is currently being drilled.

In May 2002, we entered into an exploration arrangement with El Paso Production Company (El Paso) through a farm-out transaction covering four of our prospects. El Paso has completed drilling initial exploratory wells at each of the four prospects, which resulted in two discoveries (JB Mountain and Mound Point). El Paso relinquished its rights to the other two prospects back to us. For the status of, and for more information regarding the farm-out arrangement with El Paso see "Oil and Gas Operations – Farm-Out Arrangement with El Paso" located in Items 1. and 2. "Business and Properties" of this Form 10-K.

For a summary of our drilling activities and information regarding our oil and gas properties see Items 1. and 2. "Business and Properties" of this Form 10-K.

Acreage Position

Over the past several years, our exploration team has undertaken an intensive process to evaluate our substantial acreage position from a technical standpoint. This evaluation has resulted in identification of over 20 prospects, including many deep exploration targets for natural gas accumulations in the shallow waters of the Gulf of Mexico near existing production infrastructure. On January 1, 2004, our offshore exploration agreement with Texaco Exploration and Production Inc. (Texaco), a subsidiary of Chevron Texaco Corp, expired (Note 2). Accordingly, on January 1, 2004, our exploration acreage position decreased to 52 leases, including six associated with our potential reversionary interests, encompassing approximately 201,000 gross acres and 95,000 net acres. Our acreage position also includes six Texaco leases for which we retain exploration rights until June 30, 2004 that cover approximately 31,500 gross acres and 12,200 net acres. For more information regarding our acreage position see Note 2 and "Oil and Gas Operations – Acreage" in Items 1. and 2. "Business and Properties" of this Form 10-K.

Production Update

First-quarter 2004 production rates are estimated to approximate 7 Mmcfe per day, approximately 2 Mmcfe per day below our fourth-quarter 2003 rates, reflecting the shut-in of the Vermilion Block 160 (BJ) well and the deferral of remedial operations at our Eugene Island Block 97 (Thunderbolt) field. Our production for the remainder of 2004 is estimated to average approximately 7 Mmcfe per day. Efforts are ongoing to identify opportunities to increase production levels, including the possibility of performing remedial operations at our Vermilion Block 160 field during the first half of 2004.

MAIN PASS ENERGY HUB™ PROJECT

We continue to pursue plans for the potential development of the Main Pass Energy Hub™ Project (see "Main Pass Energy Hub™ Project located in Items 1. and 2. "Business and Properties" of this Form 10-K). We have completed conceptual and preliminary engineering for the potential project. In February 2004, we filed a license application with the U.S. Coast Guard that we anticipate will authorize us to receive and process LNG and store and distribute natural gas at the facilities. We expect to spend approximately $15 million to advance the licensing process and to pursue commercial arrangements and financing for the project. As of December 31, 2003, we have incurred approximately $5.2 million of cash costs associated with our pursuit of the establishment of the Main Pass Energy Hub™.

As discussed in "K1 Business Alliance", K1 USA Energy Production Corporation (K1 USA) has the option to participate as a passive equity investor for up to 15 percent of our equity interest in the Main Pass Energy Hub™ Project. Financing arrangements may also reduce our equity interest in the project.

K1 BUSINESS ALLIANCE

In October 2002, we announced the formation of an alliance with K1 USA, a wholly owned subsidiary of k1 Ventures Limited (collectively K1), which we call K-Mc Energy Ventures. K-Mc Energy Ventures seeks to identify high quality opportunities in the energy sector. During the third quarter of 2003, we assisted K1 in its acquisition of a gas distribution utility (see "Results of Operations - Other Financial Results").

In December 2002, we and K1 USA formed K-Mc Ventures I LLC (K-Mc I), which acquired our Main Pass oil production facilities. K-Mc I is owned 66.7 percent by K1 USA and 33.3 percent by us. We continue to operate the Main Pass facilities under a management agreement. We have received a total of $10.5 million of an aggregate $13 million in proceeds from the transaction, which were intended to be used to fully fund the reclamation costs for the Main Pass structures not essential to the planned future businesses at the site (Phase I). In addition, at our request, K1 USA will provide credit support in an amount up to $10 million to provide financial assistance for K-Mc I's supplemental bonding requirements with the MMS covering the Main Pass oil assets. Also in connection with the transaction, K1 USA received stock warrants to purchase 1.74 million shares of McMoRan common stock at any time within five years at a price of $5.25 per share. During the fourth quarter of 2002, we recorded a $14.1 million gain associated with the formation of K-Mc I, which includes a $19.2 million gain on the disposition of our Main Pass oil producing assets reduced by a $5.1 million charge for the fair value of the stock warrants issued to K1 USA, as determined using the Black-Scholes valuation method on the date the warrants were issued. We are accounting for our investment in K-Mc I using the equity method.

Until September 2003, K-Mc I also had an option to acquire from us the Main Pass facilities that are planned for use in the potential Main Pass Energy Hub™ Project. In September 2003, we modified the K-Mc I transaction to eliminate that option, so that K1 USA now has the right to participate as a passive equity investor in 15 percent of our equity participation in the Main Pass Energy Hub™ Project. K1 USA would need to exercise that right upon closing of the project financing arrangements by agreeing prospectively to fund 15 percent of our future contributions to the project. K1 USA also received warrants to acquire an additional 0.76 million shares of our common stock at $5.25 per share, which expire in September 2008. Under terms of the modified agreement, K1 USA will not be required to provide credit support of up to $10 million covering the potential supplemental bonding requirements for the Main Pass Energy Hub™ Project structures as previously contemplated; however, K1 USA remains responsible for the supplemental bonding requirements associated with the Main Pass oil structures. In connection with the warrants issued to K1 USA in September 2003, we recorded a charge of approximately $6.2 million, which represented the fair value of the warrants, as determined using the Black-Scholes valuation method on the date of their issuance. This charge is included in "Start-up costs for Main Pass Energy Hub™ Project" in the accompanying consolidated statements of operations.

We jointly participated with K-Mc I in the drilling of an exploratory well at the Shiner prospect (see discussion of the Shiner well, in Items 1. and 2. "Business and Properties" of this Form 10-K). We jointly owned an approximate 50 percent working interest in the well. We retained one-third of this working interest (16.7 percent) and contributed the remaining two-thirds (33.3 percent) to K-Mc I. K-Mc I funded all the costs incurred with the drilling of the well, which did not contain commercial quantities of hydrocarbons, resulting in the well being plugged and abandoned. We have agreed to make a future payment to K-Mc I of up to one-third of the costs ($1.5 million, $0.5 million net to us) associated with the drilling of the well to the extent that K-Mc I's future cash obligations exceed its cash revenues.

CAPITAL RESOURCES AND LIQUIDITY

The table below summarizes our cash flow information by categorizing the information as cash provided by (or used in) operating activities, investing activities and financing activities and distinguishing between our continuing operations and the discontinued operations (in millions).

	For Year Ended December 31,		
	2003	2002	2001
Continuing operations			
Operating	$ (3.3)	$ (7.1)	$ 6.6
Investing	(21.5)	46.4	(105.8)
Financing	122.1	(16.6)	50.3
Discontinued operations			
Operating	$ (10.8)	$ (11.6)	$ (14.8)
Investing	0.2	58.6	6.3
Financing	-	(55.0)	9.0
Total cash flow			
Operating	$ (14.1)	$ (18.7)	$ (8.1)
Investing	(21.3)	105.0	(99.5)
Financing	122.1	(71.6)	59.3

Comparison of Year-To-Year Cash Flows

Operating

Cash used by our continuing operations in 2003 decreased from the prior year primarily reflecting an increase in our working capital, which was partially offset by lower revenues from the disposition of oil and gas properties, including our Main Pass oil interests. Cash flow from continuing oil and gas operations decreased in 2002 as compared to 2001 as a result of lower revenues, primarily from the disposition of oil and gas properties, and working capital changes. Those reductions were partially offset by lower geological and geophysical and other exploration costs, which totaled $4.2 million in 2002 and $18.3 million in 2001.

Cash used in our discontinued operations declined during 2003 as compared to 2002 primarily because of the non-recurrence of losses attributable to our sulphur operations prior to our exit from that business in mid-June 2002. That decline was partially offset by $5.7 million of Phase I reclamation costs paid in 2003 compared with $4.8 million of Phase I reclamation costs paid in 2002. Cash used in discontinued operations decreased in 2002 as compared to 2001 primarily reflecting lower reclamation costs, which totaled $5.3 million in 2002, including $4.8 million associated with Phase I reclamation activities at Main Pass, and $11.4 million in 2001. The decrease in reclamation costs reflects our entering into fixed cost contracts covering the reclamation work at the Caminada and Main Pass sulphur mines and related facilities in early 2002 (see "Discontinued Operations – Sulphur Reclamation Obligations").

Investing

Exploration and development expenditures totaled $5.5 million in 2003, which related primarily to re-completion costs associated with our Vermilion Block 160, Eugene Island Block 97 and Eugene Island Blocks 193/208/215 fields. Those expenditures also included a portion of the costs associated with the nonproductive Hurricane exploratory well at South Marsh Island Block 217 (see "Results of Operations - 2003 Compared with 2002"). We also collected $7.1 million of the $13.0 million note receivable from K-Mc I.

Our exploration and development capital expenditures totaled $17.0 million during 2002, which related primarily to the development of the Eugene Island Block 97 No. 3 well and various re-completion efforts at our other producing fields, including Eugene Island Block 97 (see Item 1. and 2. "Business and Properties" located elsewhere in this Form 10-K). Our oil and gas operations' investing cash flow during 2002 also includes the receipt of $60 million of proceeds from the sale of three oil and gas properties (see "Sales of Oil and Gas Properties" below) and the receipt of the initial $3.4 million of $13.0 million note receivable from K-Mc I.

Our exploration, development and other capital expenditures totaled $107.1 million during 2001, which includes the nonproductive exploratory drilling costs associated with five wells (see "Result of Operations -"2002 Compared with 2001"). These expenditures during 2001 also included the development costs associated with our discoveries in 2000, the exploratory well drilling costs and the related completion costs associated with the Eugene Island Block 97 No. 2 and No. 3 wells, the West Cameron Block 624 No. B-3ST well and the Louisiana State Lease 340 No. 2 well. Other capital expenditures included the costs relating to recompletion operations at West Cameron Block 616, Eugene Island Blocks 193/208/215, the Vermilion Block 160 field and the Eugene Island Block 193 C-1 well. We also sold two oil and gas leases for $1.3 million during 2001.

During 2003, cash flows from investing activities associated with our discontinued operations included proceeds from the sale of two small parcels of land previously used in our former sulphur operations. During 2002, our discontinued operations' investing cash flows included $58.0 million of gross proceeds received in connection with the transactions that resulted in our exit from the sulphur business (see "Discontinued Operations – Sale of Sulphur Assets"). The discontinued operations' investing cash flow also included proceeds of $0.6 million from a sale of miscellaneous Main Pass sulphur facility assets in 2002.

During the fourth quarter of 2001, our discontinued operations sold one of two 7500-ton self-propelled barges for $3.0 million, $2.8 million net of selling expenses. Our sulphur operations also sold various other sulphur assets from Main Pass totaling $1.0 million. In June 2001, we received $2.5 million from Homestake Sulphur Company LLC (Homestake) in a transaction associated with Main Pass (Note 7).

Financing

Cash provided by our continuing operations' financing activities during 2003 included $130.0 million of proceeds from the issuance of our 6% Convertible Senior Notes ($123 million net of issuance costs) (see "6% Convertible Senior Notes" below and Note 6) and the payment of $1.6 million of dividends on our convertible preferred stock (see "Convertible Preferred Stock" below and Note 6).

Our continuing operations used cash of $16.6 million during 2002 primarily to repay the $49.7 million of accumulated net borrowings under our oil and gas credit facility as of December 31, 2001 (see "Revolving Bank Credit Facilities" below). The repayment of this debt was partially offset by the $33.7 million of net proceeds received from the public convertible preferred stock offering in June 2002. We paid $0.9 million of dividends on the convertible preferred stock during the second half of 2002.

Our continuing operations' financing cash flow during 2001 reflects $49.7 million of net borrowings on our oil and gas credit facility used primarily to fund the development of our discoveries made in 2000 and our exploration activities.

The financing activities of our discontinued operations in 2002 reflect the repayment of the $55.0 million accumulated net borrowings outstanding under the sulphur credit facility as of December 31, 2001, following the sale of our sulphur assets and the completion of our convertible preferred stock offering. Our net borrowings under our sulphur credit facility totaled $9.0 million during 2001 and were used to fund our sulphur operations, including a reduction of working capital.

6% Convertible Senior Notes

On July 3, 2003, we issued $130 million of 6% Convertible Senior Notes due July 2, 2008. Net proceeds totaled approximately $123.0 million, $22.9 million of which was used to purchase U.S. government securities that were placed in escrow as security for the first six semi-annual interest payments. The notes are otherwise unsecured. Interest is payable on January 2 and July 2 of each year, and the first payment was made on January 2, 2004. The notes are convertible, at the option of the holder, at any time prior to maturity into shares of our common stock at a conversion price of $14.25 per share.

We intend to use the approximate $100 million of remaining net proceeds for near-term exploration expenditures associated with planned exploratory activities in 2004; for possible opportunities to acquire interests in oil and gas properties or leases; for continued efforts to pursue the Main Pass Energy Hub™ Project; and for working capital requirements and other general corporate purposes.

Convertible Preferred Stock

In June 2002, we completed a $35 million public offering of 1.4 million shares of our 5% mandatorily redeemable convertible preferred stock. Each share has a stated value of $25 and is entitled to receive quarterly cash dividends at an annual rate of $1.25 per share annually. Each share is convertible at any time at the option of the holder into 5.1975 shares of our common stock, which is equivalent to $4.81 per share and represents a 20 percent premium over our common stock's closing price on June 17, 2002. We can redeem the preferred stock, for cash after June 30, 2007, and must redeem it by June 30, 2012. During 2003, 131,615 shares of the preferred stock were tendered for conversion into approximately 0.7 million shares of our common stock. Dividends on the convertible preferred stock totaled $1.6 million in 2003 and $0.9 million during the second half of 2002.

Sales of Oil and Gas Properties

In February 2002, we sold three oil and gas properties for $60.0 million. The properties sold were Vermilion Block 196 (Lombardi), Main Pass Blocks 86/97 (Shiner), and 80 percent of our interests in Ship Shoal Block 296 (Raptor). We retained our exploration rights in these properties for prospects lying 100 feet below the stratigraphic equivalent of the deepest producing interval at the time of the sale. We used the proceeds to repay all borrowings outstanding on our oil and gas bank credit facility ($51.7 million), which was then terminated.

We retained a reversionary interest in the three properties equal to 75 percent of the transferred interests following payout of the $60 million plus a specified annual rate of return. Recently, production from the Lombardi prospect has increased as a result of additional successful drilling and development activities. Initial production from the Shiner prospect, discovered in 2000, is anticipated to commence in the first half of 2004. At December 31, 2003, the remaining amount of net proceeds required to reach payout approximated $35 million. Based on the projected future production from these properties and year-end 2003 natural gas and oil price projections, we believe that payout for these properties could occur by the end of 2004. However, no assurance can be given regarding when or if payout will occur. The independent reserve engineer's year-end 2003 estimates of our proved reserves include 2.5 Bcfe associated with our reversionary interest in these properties (Note 13).

In December 2002, we formed K-Mc I, which acquired our interests in the Main Pass oil producing assets (see "K1 Business Alliance").

Revolving Bank Credit Facilities

We repaid over $100 million in debt during 2002 and had no debt outstanding at December 31, 2002. During 2003, we issued the $130 million of 6% Convertible Senior Notes discussed above. A summary of our previous bank credit facilities is included below. We currently have no bank financing arrangements, although we may enter into such arrangements in the future, depending on our requirements and the cost and availability of bank financing.

<u>Oil and Gas Credit Facility</u> At December 31, 2001, we owed $49.7 million on our oil and gas revolving credit facility. In February 2002, we repaid all outstanding borrowings under this facility ($51.7 million) and terminated it following the sale of three oil and gas properties for $60.0 million.

<u>Sulphur Credit Facility</u> At December 31, 2001, we owed $55.0 million on our sulphur credit facility. In June 2002, following the sale of our sulphur assets and the completion of our public convertible preferred stock offering, we repaid all outstanding borrowings under the facility ($58.5 million) and terminated the facility.

Stock-Based Awards

In February 2003, our Board of Directors approved the grant of options to purchase 737,500 shares of our common stock at $7.52 per share, including, options to purchase a total of 525,000 shares that were granted to both of our Co-Chairmen from the McMoRan 2003 Stock Incentive Plan (the "2003 Plan"). Options representing a total of 300,000 shares were granted to our Co-Chairmen in lieu of cash compensation during 2003 and were immediately exercisable (Note 8).

Contractual Obligations and Commitments

The substantial majority of our former lease obligations were assumed by third parties in June 2002, following the sale of our sulphur assets (see "Discontinued Operations – Sale of Sulphur Assets"). As further described in Note 11, we are obligated to make minimum annual contractual payments under long-term contracts and operating leases, substantially all of which are associated with leases of railcars previously used in our sulphur transportation business and commercial office space in Houston, Texas. In January 2004, we agreed to sell our remaining sulphur railcars to a third party for $1.1 million and pay $7.0 million to terminate the existing operating lease (Note 12).

In 2003, we received sublease income and related reimbursement of maintenance costs of $2.6 million, representing full reimbursement of our expenses for the sulphur railcar costs.

We are contractually obligated to reimburse certain former sulphur retirees' medical costs (Note 11). Under this contractual obligation we expect to make payments currently estimated to total $43.0 million before considering the present value effect of the timing of these payments. We expect to fund these obligations with operating cash flows, future financing transactions and asset sales as necessary.

A summary of our remaining minimum annual lease payments (excluding the sulphur railcar lease payments), our expected payments for retiree medical costs and the maturity of the 6% Convertible Senior Notes is as follows (in millions):

	Medical Costs	Lease Payments	Convertible Notes	Total
2004	$ 1.6	$ 0.3	$ -	$ 1.9
2005	2.6	0.2	-	2.8
2006	2.7	0.1	-	2.8
2007	2.7	-	-	2.7
2008	2.7	-	130.0	132.7
Thereafter	30.7	-	-	30.7
Total	$ 43.0	$ 0.6	$ 130.0	$ 173.6

We anticipate our exploration activities will increase significantly during 2004 (see "Exploration Activities"). We expect to participate in the drilling of 10 to 12 wells during the next twelve months at an estimated aggregate drilling cost of $40 to $50 million, net to our planned interests. These costs are subject to change depending on the number of wells drilled, participant elections, availability of drilling rigs, the time it takes to drill each well, related personnel and material costs, and other factors, many of which are beyond our control.

RESULTS OF OPERATIONS

As a result of the sale of our sulphur assets, our only operating segment is "Oil and Gas," which includes all oil and gas exploration and production operations of MOXY. We are pursuing a new business segment, "Energy Services," whose start-up activities are reflected as a single expense line item within the accompanying consolidated statements of operations. See "Discontinued Operations" below for information regarding our former sulphur segment. The accompanying consolidated financial statements include the activities of our oil operations at Main Pass occurring on or before December 16, 2002, when these operations were acquired by K-Mc I (see "K1 Business Alliance").

We account for our interest in the K-Mc I joint venture using the equity method. We use the successful efforts accounting method for our oil and gas operations, under which our exploration costs, other than costs of successful drilling and in-progress exploratory wells, are charged to expense as incurred (Note 1). We anticipate that we will continue to experience operating losses during the near-term, primarily because of our expected exploration activities and the start-up costs associated with establishing the Main Pass Energy Hub™.

Operations

Our operating loss during 2003 totaled $38.9 million, which included $27.5 million from our oil and gas operations and $11.4 million of start-up costs for the Main Pass Energy Hub™ Project, including a $6.2 million charge associated with the issuance of stock warrants to purchase 0.76 million shares of our common stock (see "K1 Business Alliance"). The loss from our oil and gas operations included $14.1 million of exploration expense and a $3.9 million impairment charge to reduce the net book value of the Vermilion Block 160 field to its estimated fair value at December 31, 2003. We generated operating income of $17.9 million during 2002, including $44.1 million of gains associated with the disposition of oil and gas properties, which was partially offset by impairment charges aggregating $12.9 million to reduce the net book value of certain of our fields to their estimated fair values (Note 1). Our operating loss for 2001 totaled $104.9 million, which included $61.8 million of exploration expenses and asset impairment expenses totaling $39.1 million.

A summary of increases (decreases) in our oil and gas revenues between the periods follows (in thousands):

	2003	2002
Oil and gas revenues – prior year	$ 43,768	$ 72,942
Increase (decrease)		
Price realizations:		
Oil	702	(40)
Gas	4,816	(2,865)
Sales volumes:		
Oil	(68)	(2,199)
Gas	(9,038)	(3,255)
Revenues from properties sold [a]	(24,351)	(18,663)
Plant products revenue	(76)	(1,818)
Overriding royalty and other	361	(334)
Oil and gas revenues - current year	$ 16,114	$ 43,768

a. Reflects the properties sold in February 2002, the farm-out of West Cameron Block 616 in June 2002 and the sale of the oil operations at Main Pass in December 2002 (see "Capital Resources and Liquidity – Sales of Oil and Gas Properties").

See Item 6. "Selected Financial Data" for operating data, including our sales volumes and average realizations for each of the three years in the period ended December 31, 2003.

2003 Compared with 2002

Our 2003 revenues decreased approximately 63 percent compared to revenues during 2002. Oil and gas revenues for 2003 reflect decreased sales volumes of both gas (66 percent) and oil (90 percent) compared with 2002. The decreases were partially offset by increases in the average realization received for both gas (88 percent) and oil (38 percent) over prices received in 2002. The decrease in oil sales was primarily attributable to the disposition of the Main Pass oil operations, which were acquired by K-Mc I in December 2002. The decrease in gas sales primarily reflects the sale of two producing properties in February 2002, the cessation of production from our West Cameron Block 624 field, the unexpected shut-in of production from the Eugene Island Block 193 C-1 and Vermilion Block 160 AJ-6 wells and the timing of certain remedial and re-completion activities, as well as normal depletion of our producing properties.

Our revenues during 2003 included $0.8 million of plant product revenues associated with approximately 20,700 equivalent barrels of oil and condensate received for products (ethane, propane, butane, etc.) recovered from the processing of our natural gas, compared to $0.9 million for plant product from 26,100 equivalent barrels during 2002.

Production and delivery costs totaled $7.1 million in 2003 compared to $26.2 million in 2002. The decrease is primarily attributable to the disposition of the Main Pass oil operations, where production and delivery costs totaled $19.1 million prior to the sale of those operations to K-Mc I in December 2002. The decrease also reflects lower production volumes during 2003, which was offset by increased workover costs that totaled $1.5 million in 2003 and $1.2 million in 2002. During 2003, we performed workovers at the Vermilion Block 160, Eugene Island Blocks 193/208/215 and Eugene Island Block 97 fields. For more information regarding our operating activities related to our oil and gas fields, see Items 1. and 2. "Business and Properties" of this Form 10-K.

We follow the units-of-production method for calculating depletion, depreciation and amortization expense for our oil and gas properties (Note 1). Depletion, depreciation and amortization expense totaled $14.1 million in 2003 compared with $24.1 million in 2002. The fluctuation reflects the following:

1) The decrease in sales volumes reflecting the sale of two producing properties in February 2002, the farm-out of our West Cameron Block 616 field in June 2002, the depletion of the West Cameron Block 624 field in September 2002 and the disposition of our oil operations at Main Pass in December 2002;
2) Impairment charges (see below) totaling $3.9 million during 2003 compared with $7.6 million in 2002. (see "2002 Compared with 2001" below for more detail of our 2002 impairment charges);
3) The use of higher units-of-production depreciation rates during 2003 compared to those used in 2002 reflecting either a higher average capitalized balance for certain of our fields or downward revisions to proved and proved developed reserve estimates for certain of our fields; and
4) The implementation of Statement of Financial Accounting Standards No. 143 *"Accounting for Asset Retirement Obligations"* (SFAS 143), effective January 1, 2003 (Note 1). Pursuant to the requirements of SFAS 143, we recorded accretion expense totaling $0.5 million associated with our oil and gas asset retirement obligations, which we classified as depletion, depreciation and amortization expense.

As further explained in Note 1, accounting rules require that the carrying value of proved oil and gas property costs be assessed for possible impairment under certain circumstances, and reduced to fair value by a charge to earnings if impairment is deemed to have occurred. Conditions affecting current and estimated future cash flows that could require impairment charges include, but are not limited to, lower anticipated oil and gas prices, increased production, development and reclamation costs and downward revisions of reserve estimates. As more fully explained under "Risk Factors" elsewhere in this Form 10-K, a combination of any or all of these conditions could require impairment charges to be recorded in future periods.

Our future exploration expenses will fluctuate based on the structure of our drilling arrangements (i.e. the extent to which exploratory costs are financed by other participants or by us), the number, results, and costs of exploratory drilling projects financed by us and the incurrence of geological and geophysical costs, including purchases of seismic data. Summarized exploration expenses are as follows (in millions):

	Years Ended December 31,	
	2003	2002
Geological and geophysical, including 3-D seismic purchases	$ 4.5	$ 3.9
Dry hole costs	8.8 [a]	9.1 [b]
Other	0.8	0.3
	$ 14.1	$ 13.3

a. Includes a $4.0 million charge to fully impair the remaining leasehold costs for the Hornung prospect at Eugene Island Blocks 96/97/108/109 following the expiration of two of the leases comprising the prospect in mid-2003. Also includes $1.0 million of nonproductive drilling costs associated with the exploratory well at Garden Banks Block 228 (Cyprus) (discussed below). In January 2004, the exploratory well at South Marsh Island Block 217 was determined to be non-commercial. Accordingly, we charged the $3.2 million of costs incurred on this well through December 31, 2003 to exploration expense as required under accounting standards.

b. Includes a $5.3 million charge to impair a portion of the leasehold acquisition costs of the Hornung prospect following the determination that the initial Hornung exploratory well at Eugene Island Block 108 did not contain commercial quantities of hydrocarbons. Also includes residual costs associated with various nonproductive exploratory wells drilled in prior years totaling $1.4 million and certain leasehold amortization costs. In connection with the February 2003 determination that the Cyprus exploratory well was nonproductive, we charged our share of the well's drilling costs incurred through December 31, 2002 ($0.1 million) to exploration expense for the year then ended.

2002 Compared with 2001

Our 2002 revenues decreased approximately 40 percent from 2001 revenues primarily reflecting decreased production volumes of both gas (47 percent) and oil (19 percent) from 2001. Our comparable revenues were also adversely affected by a 19 percent decrease in the average price realized on our natural gas sales in 2002 from those received in 2001 partially offset by a slight increase (1 percent) in the average per barrel price we received from our oil sales during 2002 compared to those received in 2001. The decrease in sales volumes between the comparable periods reflects:

1) the sale of three oil and gas properties in February 2002, two of which commenced production in mid-2001;
2) the farm-out of our West Cameron Block 616 field in June 2002;
3) severe weather conditions in the Gulf of Mexico that shut-in certain of our producing fields for portions of September and October 2002;
4) routine shut-ins for pipeline maintenance by other companies involving our fields; and
5) the timing and results of certain re-completion and remedial efforts we performed during 2002.

Our oil sales volumes from Main Pass totaled 1.0 million barrels during 2002 and 2001, reflecting the additional 16.7 percent ownership interest in Main Pass we purchased in June 2001 (see "Capital Resources and Liquidity" and Note 7) and the operations only having 11 months of production in 2001 because the shut-in of operations during February 2001 for the performance of platform and equipment maintenance. The increase was partially affected by Main Pass being shut-in during portions of September and October 2002 because of the severe weather conditions in the Gulf of Mexico, work to enhance production in the field (see Items 1. and 2. "Business and Properties" located elsewhere in this Form 10-K) and the reclamation work being conducted on certain sulphur facilities at the field (see "Discontinued Operations – Sulphur Reclamation Obligations").

Our revenues during 2002 included $0.9 million of plant product revenues associated with approximately 26,100 equivalent barrels of oil and condensate received for our products recovered from the processing of our natural gas. Our plant product revenues during 2001 totaled $3.0 million associated with 81,100 equivalent barrels of oil and condensate. The decrease in our plant products is primarily the result of the sale of two producing properties in February 2002.

Production and delivery costs totaled $26.2 million during 2002 compared with $35.0 million during 2001. The decrease between the comparable periods reflects the following:

1) The decrease in sales volumes reflecting the sale of two producing properties in February 2002, the farm-out of our West Cameron Block 616 field in June 2002 and the disposition of our oil operations at Main Pass in December 2002;

2) Well workover costs totaled $1.2 million in 2002 compared to $6.5 million in 2001. Our 2002 workover costs include our unsuccessful efforts to re-establish production from the Mound Point No. 2 well at Louisiana State Lease 340 and the remedial operations at the Eugene Island Block 193 C-1 well; and
3) A decrease in our Main Pass oil production and delivery costs reflecting reduced platform and equipment maintenance cost, including $1.9 million of costs associated with our activities that shut in the field in February 2001, partially offset by the costs associated with our efforts to enhance production and reduce the ongoing cost of operations at the field.

Depletion, depreciation and amortization expense totaled $24.1 million in 2002 compared with $65.9 million in 2001. The fluctuation in our depletion, depreciation and amortization expense reflects the following:

1) The decrease in sales volumes from the sale of two producing properties in February 2002, the farm-out of our West Cameron Block 616 field in June 2002 and the disposition of our oil operations at Main Pass in December 2002;
2) Impairment charges (see "2003 Compared with 2002" above) totaling $7.6 million during 2002 compared with $39.1 million in 2001. Our impairment charges for 2002 included a $4.4 million charge to reduce the net book value of our Eugene Island Block 97 field to its estimated fair value at December 31, 2002 and a $3.2 million charge to writeoff the remaining asset carrying value of the West Cameron Block 624 field after it ceased production in September 2002; and
3) The use of higher units-of-production depreciation rates during 2002 compared to those used in 2001 reflecting either a higher average capitalized balance for certain of our fields and downward revisions to proved and proved developed reserve estimates for certain of our fields.

Our exploration expenses fluctuate based on the structure of our arrangements to drill exploratory wells (i.e. the extent to which exploratory costs are financed by other participants or by us), the number, results, and costs of exploratory drilling projects financed by us and the incurrence of geological and geophysical costs, including purchases of seismic data. Summarized exploration expenses are as follows (in millions):

	Years Ended December 31,	
	2002	2001
Geological and geophysical,		
Including 3-D seismic purchases	$ 3.9	$ 15.7
Dry hole costs	9.1 [a]	43.5 [b]
Other	0.3	2.6
	$ 13.3	$ 61.8

a. For details see "2003 Compared with 2002" above.
b. Includes nonproductive exploratory well drilling and related costs, primarily associated with the West Delta Block 12 No. 1 and Garden Banks Block 272 No. 1 wells. Also includes the nonproductive exploratory well costs associated with the Louisiana State Lease 340 No. 3 and Viosca Knoll Block 863 No. 1 wells and additional plugging and abandonment costs associated with the Vermilion Block 144 No. 3 well.

Other Financial Results

Operating. Our general and administrative expenses totaled $8.3 million in 2003, $6.4 million in 2002 and $15.1 million in 2001. The increase in 2003 from 2002 reflects higher expenses associated with our oil and gas exploration activities, the pursuit of the Main Pass Energy Hub™ and costs related to the pursuit of additional energy business opportunities through K-Mc Energy Ventures (see below). The increase also reflects $0.8 million of noncash compensation costs related to stock-based awards (Note 8). The decrease in 2002 from 2001 reflects reduced administrative costs as a result of the sale of certain of our oil and gas properties, the decrease in our exploration and development activities, the sale of our sulphur assets, and efforts to reduce personnel and related costs, including the effect of our Co-Chairmen not receiving any cash compensation during 2002 (Note 8) and other reduced costs under the FM Services contract (Note 10), which totaled $2.2 million in 2002 and $10.6 million in 2001 (including $0.2 million in 2002 and $1.5 million in 2001 associated with the discontinued operations).

During the first quarter of 2002, we recorded a $29.2 million gain from the sale of our ownership interests in the Lombardi and Shiner prospects and 80 percent of our interests in the Raptor prospect (see "Capital Resources and Liquidity - Sales of Oil and Gas Properties"). During the second quarter of 2002, we recorded a $0.8 million gain from the disposition of our interests in West Cameron Block 616. In the fourth quarter of 2002, we recognized a $14.1 million gain associated with the formation of K-Mc I and its acquisition of our Main Pass oil producing assets (see "K1 Business Alliance").

Non-Operating. Interest expense, net of capitalized interest, totaled $4.6 million in 2003, $0.7 million in 2002 and $0.4 million for 2001. We had no capitalized interest during 2003 because we had no debt until July 2003, when we issued our 6% Convertible Senior Notes (see "Capital Resources and Liquidity – 6% Convertible Senior Notes), and since that time we have had no qualifying capital expenditures through the end of 2003. We capitalized interest totaling $0.3 million during 2002 and $1.5 million during 2001. At December 31, 2001, amounts outstanding under the oil and gas credit facility totaled $49.7 million, reflecting borrowings primarily used to fund the development of our 2000 discoveries and exploration activities during 2001. For additional information regarding our credit facilities, including the repayment of the entire amount under both our oil and gas and sulphur credit facilities and their subsequent termination, see "Capital Resources and Liquidity – Revolving Bank Credit Facilities" and Note 6.

Other income totaled $1.7 million in 2003, $1.3 million in 2002 and $0.5 million in 2001. Our non-operating income for 2003 primarily included a one-time $1.5 million advisory fee paid to us by K1 for management services related to its acquisition of a gas distribution utility in August 2003. Under our management services agreement with the newly acquired gas utility, we will earn an additional $1.8 million fee over a twelve-month period, beginning in August 2003, for providing continuing services. These amounts are recorded as a reduction of our general and administrative expense. Our non-operating income during 2002 primarily reflects the sale of our equity investment in FM Services for $1.3 million, resulting in a gain of $1.1 million (Note 10), with the remaining $0.2 million representing interest income. Other non-operating income during 2001 reflects the gain on the sale of two leases with the remainder representing interest income.

DISCONTINUED OPERATIONS

During 2002 we completed exiting the sulphur business by selling substantially all our remaining sulphur assets in June 2002 (Note 7). We had previously ceased all our sulphur-mining activities in August 2000. As a result of the sale of substantially all our remaining sulphur assets, the results of operations of our former sulphur business are recorded as discontinued operations in the accompanying consolidated financial statements. Our former sulphur operations' results are summarized in Note 7.

Our discontinued operations resulted in a net loss of $11.2 million in 2003, $0.5 million in 2002 and $43.3 million in 2001. During 2003, we recorded an aggregate charge of $5.9 million associated with the estimated loss on the ultimate disposal of our remaining sulphur railcars (see below). The discontinued operations' loss during 2003 also included charges for certain retiree-related costs totaling $2.1 million and accretion expense of $0.5 million related to our sulphur reclamation obligations following our adoption of SFAS 143 (see "Results of Operations" above and Note 1). The remaining 2003 discontinued operations' loss primarily includes caretaking and insurance costs associated with our closed sulphur facilities and legal costs.

Our discontinued operations results during 2002 included a $5.2 million gain resulting from a reduction in the accrued reclamation liability covering the Phase I structures at Main Pass based on a fixed fee contractual arrangement (see "Sulphur Reclamation Obligations" below), a $5.0 million gain associated with the completion of the Caminada mine reclamation activities, offset in part by an aggregate $4.6 million loss on the disposal of the sulphur business assets, a $1.8 million operating loss from the sulphur operations prior to their sale in June 2002 (see "Sale of Sulphur Assets" below), and $1.8 million of interest expense prior to the termination of the sulphur credit facility.

At December 31, 2003, we had an operating lease involving sulphur railcars previously used in our sulphur business (Note 11). We also were party to a sublease arrangement covering all our railcars through December 31, 2003, which provided sufficient sublease income to offset the related lease expense (see "Capital Resources and Liquidity-Contractual Obligations and Commitments"). In the third quarter of 2003, we received correspondence from the user of our remaining sulphur railcars stating its intention to terminate our sublease agreement, which was scheduled to expire on December 31, 2003. The sublease is now continuing on a month-to-month basis. In January 2004, we sold our sulphur railcars to a third party for $1.1 million (Note 12). The delivery of the railcars to the third party will occur over the first four months of 2004.

The railcars, which were subject to an operating lease that was scheduled to terminate in 2011, provided for the acceleration of remaining lease payments upon cancellation of the lease. The lease provided that we are entitled to any proceeds from the sale of the railcars. Because of the unexpected early termination of the sublease agreement and weak market conditions for these railcars, we recorded a $5.9 million estimated loss in 2003 related to our pending disposal of the sulphur railcars.

During the fourth quarter of 2001, we incurred increased costs associated with our contractual obligation to reimburse certain former sulphur retirees' medical costs (Note 11). An updated year-end estimate of these projected future costs was prepared by our external benefit consultants using an increased health care cost trend rate to conform to then current expectations. As a result, we accrued $13.6 million to increase the recorded liability for estimated future payments under this contractual obligation. Interest on the obligation totaled $1.9 million in 2003, $1.7 million during 2002 and $0.8 million in 2001.

Sale of Sulphur Assets

On June 14, 2002, we sold substantially all the assets used in our sulphur transportation and terminaling business to Gulf Sulphur Services Ltd., LLP, a sulphur joint venture owned equally by IMC Global Inc. (IMC Global) and Savage Industries Inc. In connection with this transaction, all outstanding disputes between IMC Global, its subsidiaries and us were settled. In addition, our contract to supply sulphur to IMC Global also terminated upon completion of the transactions. The transactions provided us with $58.0 million in gross proceeds, which we used to partially fund our remaining sulphur working capital requirements, transaction costs and to repay a substantial portion of our borrowings under the sulphur credit facility (Note 6). At December 31, 2003, approximately $1.0 million (including accumulated interest income) of funds from these transactions remained deposited in various restricted escrow accounts, which will be used to fund a portion of our remaining sulphur working capital requirements and to provide the potential funding for certain retained environmental obligations discussed further below. We recorded an aggregate loss of $4.6 million during 2002 associated with the disposal of the sulphur business assets, including a loss on the disposal of certain railcars sold in late 2002.

In connection with the preceding transactions, we have also agreed to be responsible for any historical environmental obligations relating to our sulphur transportation and terminaling assets and have also agreed to indemnify Gulf Sulphur Services and IMC Global from any liabilities with respect to the historical sulphur operations engaged in by our predecessor companies, and us, including reclamation obligations. In addition, we assumed, and agreed to indemnify IMC Global from, any obligations, including environmental obligations, other than liabilities existing and identified as of the closing of the sale, associated with the historical oil and gas operations undertaken by the Freeport-McMoRan companies prior to the 1997 merger of Freeport-McMoRan Inc. and IMC Global. See "Risk Factors" included elsewhere in this Form 10-K.

MMS Bonding Requirement Status

Prior to 2002, we completed certain reclamation activities at the Main Pass sulphur mine, including the plugging and abandonment of the sulphur wells and the removal of the living quarters and warehouse facility. We incurred reclamation costs totaling $9.8 million during 2001 associated with these reclamation activities.

In July 2001, the MMS, which has regulatory authority to ensure that offshore leaseholders fulfill the abandonment and site clearance obligations related to their properties, informed us that they were considering requiring us or Freeport Energy either to post a bond of approximately $35 million or to enter into other funding arrangements acceptable to the MMS, relative to reclamation of the Main Pass sulphur mine and related facilities as well as the Main Pass oil production facilities. In October 2001, Freeport Energy entered into a trust agreement with the MMS to provide financial assurances meeting the MMS requirements by February 3, 2002. The MMS has subsequently extended the compliance date for the trust agreement, most recently until February 17, 2004. On February 16, 2004, we proposed to the MMS that the trust agreement between Freeport Energy and the MMS be terminated and replaced with financial assurances from MOXY. In addition, if requested by us, K1 USA will provide credit support to cover up to $10 million of MMS bonding requirements covering the Main Pass oil assets now owned by K-Mc I. We and our subsidiaries' ongoing compliance with applicable MMS requirements will be subject to meeting certain financial and other criteria.

Sulphur Reclamation Obligations

In the first quarter of 2002, we entered into Turnkey Contracts with Offshore Specialty Fabricators Inc. (OSFI) for the reclamation of the Main Pass and Caminada sulphur mines and related facilities located offshore in the Gulf of Mexico. During the second quarter of 2002, OSFI completed its reclamation activities at the Caminada mine site and we recorded a $5.0 million gain associated with the resolution of our Caminada sulphur reclamation obligations and the related conveyance of assets to OSFI, as further discussed below. In August 2002, OSFI commenced its Phase I reclamation work at Main Pass, that work has been substantially completed. We recorded a $5.2 million gain during 2002 in connection with the reduction in the estimated Phase I accrued Main Pass reclamation costs. The gains from both the Caminada and Phase I reclamation activities are included within the caption "Loss from discontinued operations" in the accompanying consolidated statements of operations and the remaining obligation for the Phase I reclamation obligation is included in current liabilities in the accompanying consolidated balance sheet at December 31, 2003.

As payment of our share of these reclamation costs, we conveyed certain assets to OSFI including a supply service boat, our dock facilities in Venice, Louisiana, and certain assets we previously salvaged during a prior reclamation phase at Main Pass. When we entered into the contractual agreements with OSFI, both parties expected to dispose of the Main Pass oil facilities and related reclamation obligations through a sale of those assets to a specified third party with payment of the sales proceeds to be remitted to OSFI as it completed the Phase I Main Pass sulphur reclamation activities. In addition, the parties contemplated that a third party would acquire the remaining Main Pass sulphur facilities and establish and operate a new business enterprise. As contemplated, we would have received an initial cash payment, which would have been paid to OSFI for its reclamation work, and we would have shared a retained revenue or profit interest from this new enterprise with OSFI. Neither the sale transaction nor the formation of the new business enterprise occurred.

In August 2002, both parties jointly amended the contract to clarify certain aspects, including specifying values for the reclamation of the Phase I structures at Main Pass. Under the terms of this arrangement compensation for Phase I reclamation activities was to be $13 million and OSFI's compensation for reclamation obligations outside of Phase I (Phase II) was the potential share of retained revenue or profit interest described above. We had no fixed obligation to pay this $13 million, as it was contingent upon the conclusion of the two specified transactions. Following the failure of the two specified transactions to occur, OSFI informed us that it could not perform the reclamation obligations that it had assumed under the Turnkey Contract. We then reached a further agreement with OSFI which, in substance, provided that if OSFI received $13 million for Phase I reclamation and was released from its Phase II reclamation obligation, OSFI would have no right to participate in any royalty or net profit interest or any other right relating to the sale of the sulphur lease and Phase II sulphur facilities. OSFI has refused to honor this agreement. In order to fund this $13 million amount, we entered into the K-Mc I joint venture and conveyed to it the Main Pass oil facilities (see "K1 Business Alliance").

As a result of the various changes in the structure of the arrangement with OSFI, the formation of K-Mc I, our plans for the Main Pass Energy Hub™ Project, and OSFI's performance of its Phase I reclamation activities, we elected to release OSFI from the Phase II reclamation obligations and its potential future participation in any use of the remaining Main Pass sulphur facilities. We are currently involved in litigation with OSFI with respect to the rights and obligations of each party under these arrangements (see Part I, Item 3. "Legal Proceedings" of this Form 10-K). In the event that the remaining Main Pass sulphur facilities cannot be used in the future to establish a new business, additional reclamation work covering the remaining sulphur facilities will be required on an accelerated basis.

Through December 31, 2003, we received $10.5 million of the $13.0 million of proceeds from K-Mc I, and paid these amounts to OSFI for the Phase I reclamation work performed. One of the issues in the dispute with OSFI is the possible refund of the $10.5 million. See Item 3. "Legal Proceedings."

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Management's Discussion and Analysis of our financial condition and results of operations is based upon our consolidated financial statements, which have been prepared in conformity with accounting principles generally accepted in the United States. The preparation of these statements requires that we make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. We base these estimates on historical experience and on assumptions that we consider reasonable under the circumstances; however, reported results could differ from the current estimates under different assumptions and/or conditions. The areas requiring the use of management's estimates are discussed in Note 1 to our consolidated financial statements under the heading "Use of Estimates." The assumption and estimates described below are our critical accounting estimates.

Management has reviewed the following discussion of its development and selection of critical accounting estimates with the Audit Committee of our Board of Directors.

- **Reclamation Costs.** Both our oil and gas and former sulphur operations have significant obligations relating to the dismantlement and removal of structures used in the production or storage of proved reserves and the plugging and abandoning of wells used to extract the proved reserves. The substantial majority of our reclamation obligations are associated with facilities located in the Gulf of Mexico, which are subject to the regulatory authority of the MMS. The MMS ensures that offshore leaseholders fulfill the abandonment and site clearance responsibilities related to their properties in accordance with applicable laws and regulations in existence at the time such activities are commenced. Current laws and regulations stipulate that upon completion of operations, the field is to be restored to substantially the same condition as it was before extraction operations commenced. All of our current oil and gas reclamation obligations are in the Gulf of Mexico except for any possible residual oil and gas obligations we assumed from IMC Global in June 2002 (see below and "Discontinued Operations – Sale of Sulphur Assets"). Previously we accrued our estimated reclamation costs on a field-by-field basis using the units-of-production method over the related estimated proved reserves. For a discussion of the estimated proved reserves see "Depletion, Depreciation and Amortization" below. Effective January 1, 2003, we implemented a new accounting standard that significantly modified the method to which we recognize and record our accrued reclamation obligations (see below).

Our sulphur reclamation obligations are associated with our former sulphur mining operations. In June 2000 we elected to cease all mining operations, which resulted in a charge to fully accrue the estimated reclamation costs associated with our Main Pass sulphur mine and related facilities and the related storage facilities at Port Sulphur, Louisiana. We had previously fully accrued all estimated costs associated with the closed Caminada sulphur facilities. We have also accrued the estimated reclamation costs associated with our closed Grand Ecaille sulphur facilities, which were closed and reclaimed in accordance with the laws and regulations in effect at the time of its closure (1978). During 2002, we entered into fixed cost contracts to perform a substantial portion of our sulphur reclamation work. All the work associated with the Caminada mine and related facilities was subsequently completed and the Phase I reclamation work at the Main Pass facilities has also been substantially completed (see "Discontinued Operations – Sulphur Reclamation Obligations").

Effective January 1, 2003, we adopted Statement of Financial Accounting Standard No. 143, "*Accounting for Asset Retirement Obligations*" (SFAS 143). SFAS 143 requires that we record the fair value of our estimated asset retirement obligations in the period incurred, rather than accrued as the related reserves are produced. Upon implementation of SFAS 143, we recorded the fair value of the obligations relating to our oil and gas operations together with the related additional asset cost. For our closed sulphur facilities, we did not record any related assets with respect to our asset retirement obligations but reduced our current accrued obligations by approximately $19.4 million to their estimated fair value. We recorded an aggregate $22.2 million gain upon the adoption of this standard, which is reflected as "cumulative effect gain on change in accounting principle" in the accompanying consolidated statements of operations.

The accounting estimates related to reclamation costs are critical accounting estimates because 1) the cost of these obligations is significant to us; 2) we will not incur most of these costs for a number of years, requiring us to make estimates over a long period; 3) new laws and regulations regarding the standards required to perform our reclamation activities could be enacted and such changes could materially change our current estimates of the costs to perform the necessary work; 4) calculating the fair value of our asset retirement obligations under SFAS 143 requires management to assign probabilities and projected cash flows, to make long-term assumptions about inflation rates, to determine our credit-adjusted, risk-free interest rates and to determine market risk premiums that are appropriate for our operations; and 5) given the magnitude of our estimated reclamation and closure costs, changes in any or all of these estimates could have a material impact on our results of operations and our ability to fund these costs.

We used estimates prepared by third parties in determining our January 1, 2003 estimated asset retirement obligations under multiple probability scenarios reflecting a range of possible outcomes considering the future costs to be incurred, the scope of work to be performed and the timing of such expenditures. Using this approach, the estimated retirement obligations associated with our oil and gas operations was $9.8 million and for our former sulphur operations approximated $32.3 million. The total of these estimates is less than the estimates on which the obligations were previously accrued because of the effect of applying weighted probabilities to the multiple scenarios used in this calculation lower than the most probable case, which was the basis of the previous accrual. To calculate the fair value of the estimated obligations, we applied an estimated long-term inflation rate of 2.5 percent and a market risk premium of 10 percent, which was based on market-based estimates of rates that a third party would have to pay to insure its exposure to possible future increases in the costs of these obligations. We discounted the resulting projected cash flows at our estimated credit-adjusted, risk-free interest rates, which ranged from 4.6 percent to 10 percent, for the corresponding time periods over which these costs would be incurred.

At December 31, 2003, we revised our reclamation and well abandonment estimates for (1) changes in the projected timing of certain reclamation costs because of changes in reserve estimates and (2) changes in our credit-adjusted risk free interest rate, which ranged from 4.8 percent to 10.0 percent over the period these reclamation costs would be incurred. At December 31, 2003, our estimated undiscounted reclamation obligations totaled approximately $35.9 million, including $26.7 million associated with our remaining sulphur obligations. At December 31, 2003, our estimated discounted asset retirement obligations totaled $21.3 million, including $14.0 million associated with our remaining sulphur obligations. These obligations include $2.8 million of current obligations, including $2.6 million associated with our sulphur obligations. A one percent increase in the inflation rate used in our estimates results in a $1.0 million increase in the aggregated discounted asset retirement obligations, while a one percent decrease results in a $1.6 million decrease in the estimated discounted asset retirement obligations. A one percent change in the market risk premium results in an approximate $0.2 million change to our estimated discounted asset retirement obligations. Assuming no significant changes in our currently estimated retirement obligations, we expect that our adoption of SFAS 143 will cause future results of operations to include accretion expense as well as higher charges for depletion, depreciation and amortization than we otherwise would have recorded.

- **Depletion, Depreciation and Amortization.** As discussed in Note 1, our depletion, depreciation and amortization for our oil and gas producing assets is calculated on a field-by-field basis using the units-of-production method based on independent petroleum engineers' estimates of our proved reserves. Unproved properties having individually significant leasehold acquisition costs on which management has specifically identified an exploration prospect and plans to explore through drilling activities are individually assessed for impairment. We amortize the value of our remaining unproved properties, on a straight-line basis over the remaining life of the leases. We have fully depreciated all of our other remaining assets.

The accounting estimates related to depletion, depreciation, and amortization are critical accounting estimates because:

1) The determination of our proved oil and gas proved reserves involves inherent uncertainties. The accuracy of any reserve estimate depends on the quality of available data and the application of engineering and geological interpretations and judgments. Different reserve engineers may make different estimates of proved reserve quantities and estimates of cash flows based on varying interpretations of the same available data. Estimates of proved reserves for wells with limited or no production history are less reliable than those based on actual production history.

2) The assumptions used in determining whether reserves can be produced economically can vary. The key assumptions used in estimating our proved reserves include:

a) Estimated future oil and gas prices and future operating costs.
b) Projected production levels and the timing and costs of future development costs, remedial activities, and abandonment costs.
c) Assumed effects of government regulations on our operations.
d) Historical production from the area compared with production in similar producing areas.

Changes to our estimates of proved reserves could result in changes to our depletion, depreciation and amortization expense, with a corresponding effect on our results of operations. If aggregate estimated proved reserves were 10 percent higher or lower at December 31, 2003, we estimate that our annual depletion, depreciation and amortization expense for 2004 would change by approximately $1 million, with a corresponding change being reflected in our results of operations. Changes in our estimates of proved reserves may also affect our assessment of asset impairment (see below). We believe that if our aggregate estimated proved reserves were revised, such a revision could have a material impact on our results of operations, liquidity and capital resources.

As discussed in Note 1, we review and evaluate our oil and gas properties for impairment when events or changes in circumstances indicate that the related carrying amounts may not be recoverable. In these impairment analyses we consider both our proved reserves and risk assessed probable reserves, which generally are subject to a greater level of uncertainty than our proved reserves. Decreases in reserve estimates may cause us to record asset impairment charges against our results of operations.

- **Postretirement and other employee benefits costs.** As discussed in Note 11, we have a contractual obligation to reimburse IMC Global for a portion of their postretirement medical benefit costs relating to certain former retired sulphur employees. This obligation is based on numerous estimates of future health care cost trends, retired sulphur employees' life expectancy, liability discount rates and other factors. We also have similar obligations for our employees although the number of employees covered by our plan is significantly less than those covered under our contractual obligation to IMC Global. The amount of these postretirement and other employee benefit costs are critical accounting estimates because fluctuations in health care cost trend rates and liability discount rates may affect the amount of future payments we would expect to make. The initial health care cost trend used was 12 percent in 2003, decreasing ratably annually until reaching 5 percent in 2010. A one-percentage point increase or decrease in assumed health care cost trend rates would have an approximate $2.0 million impact on our net income. See Notes 8 and 11 for additional information regarding postretirement and other employee benefit costs. In the case of obligations relating to certain former retired sulphur employees the impact of any changes in assumptions of the related obligation will be charged to results of operations currently. These benefit plans are subject to modification and accordingly, any modifications could also affect the estimated obligations regarding these future costs.

DISCLOSURES ABOUT MARKET RISKS

Our revenues are derived from the sale of crude oil and natural gas. Our results of operations and cash flow can vary significantly with fluctuations in the market prices of these commodities. Based on projected annual sales volumes from both existing producing properties and those expected to produce later in 2004, a change of $0.10 per Mcf in the average prices realized on natural gas sales would have an approximate $0.2 million net impact on both revenues and net income (loss). A $1 per barrel change in the average realization of oil sold would have an approximate $0.1 million net impact on revenues and net income (loss).

At the present time we do not hedge our exposure to fluctuations in interest rates because we currently do not have any bank financing, including revolving credit facilities that would exposes us to interest rate risk. Our convertible senior notes have a fixed interest rate of six percent.

Since we conduct all of our operations within the U.S. in U.S. dollars and have no investments in equity securities, we currently are not subject to foreign currency exchange risk or equity price risk.

ENVIRONMENTAL

We and our predecessors have a history of commitment to environmental responsibility. Since the 1940's, long before public attention focused on the importance of maintaining environmental quality, we have conducted pre-operational, bioassay, marine ecological and other environmental surveys to ensure the environmental compatibility of our operations. Our environmental policy commits our operations to compliance with local, state, and federal laws and regulations, and prescribes the use of periodic environmental audits of all facilities to evaluate compliance status and communicate that information to management. We believe that our operations are being conducted pursuant to necessary permits and are in compliance in all material respects with the applicable laws, rules and regulations. We have access to environmental specialists who have developed and implemented corporate-wide environmental programs. We continue to study methods to reduce discharges and emissions.

Federal legislation (sometimes referred to as "Superfund" legislation) imposes liability for cleanup of certain waste sites, even though waste management activities were performed in compliance with regulations applicable at the time of disposal. Under the Superfund legislation, one responsible party may be required to bear more than its proportional share of cleanup costs if adequate payments cannot be obtained from other responsible parties. In addition, federal and state regulatory programs and legislation mandate clean up of specific wastes at operating sites. Governmental authorities have the power to enforce compliance with these regulations and permits, and violators are subject to civil and criminal penalties, including fines, injunctions or both. Third parties also have the right to pursue legal actions to enforce compliance. Liability under these laws can be significant and unpredictable. We have, at this time, no known significant liability under these laws.

We estimate the costs of future expenditures to restore our oil and gas and sulphur properties to a condition that we believe complies with environmental and other regulations. These estimates are based on current costs, laws and regulations. These estimates are by their nature imprecise and are subject to revision in the future because of changes in governmental regulation, operation, technology and inflation.

We previously fully accrued the remaining estimated costs to reclaim and restore our sulphur mines and related facilities. As of December 31, 2002, our remaining accrual for these costs totaled $38.5 million. During 2002, we reduced our sulphur reclamation obligations by $25.3 million, following the execution of fixed cost contracts and the completion of their Caminada mine reclamation activities. The Phase I reclamation activities at Main Pass are now substantially complete (see "Discontinued Operations – Sulphur Reclamation Obligations").

Estimated future expenditures to restore our oil and gas properties and related facilities to a condition that we believe would comply with environmental and other regulations were previously accrued over the life of the properties (Note 1). At December 31, 2002, the total estimated abandonment costs accrued for our oil and gas properties totaled $8.0 million, with an estimated $1.5 million remaining to be accrued. In December 2002, after our disposition of the oil operations at Main Pass, we reduced our accrued oil and gas reclamation obligations by $9.4 million (Note 2).

As discussed in "Critical Accounting Policies and Estimates" above and in Note 1, effective January 1, 2003 we implemented a new accounting standard that has reduced both our oil and gas and sulphur reclamation obligations. These reductions were recorded as a cumulative effect of change in accounting principle in the accompanying consolidated statements of operations.

As discussed above, in connection with our sale of our sulphur transportation and terminaling assets, we agreed to be responsible for any historical environmental obligations relating to those assets and we agreed to indemnification obligations with respect to the historical sulphur operations engaged in by us and our predecessor companies. In addition, we agreed to assume, and indemnify IMC Global from, any obligations, including environmental obligations, other than liabilities existing and identified as of the closing of the sale, associated with historical oil and gas operations undertaken by the Freeport-McMoRan companies prior to the 1997 merger of Freeport-McMoRan Inc. and IMC Global.

We have made, and will continue to make, expenditures at our operations for the protection of the environment. Continued government and public emphasis on environmental issues can be expected to result in increased future investments for environmental controls, which will be charged against income from future operations. Present and future environmental laws and regulations applicable to current operations may require substantial capital expenditures and may affect operations in other ways that cannot now be accurately predicted.

We maintain insurance coverage in amounts deemed prudent for certain types of damages associated with environmental liabilities that arise from sudden, unexpected and unforeseen events.

CAUTIONARY STATEMENT

Management's Discussion and Analysis of Financial Condition and Results of Operations and Disclosures about Market Risks contains forward-looking statements. All statements other than statements of historical fact in this report, including, without limitation, statements, plans and objectives of our management for future operations and our exploration and development activities are forward-looking statements. Factors that may cause our future performance to differ from that projected in the forward-looking statements are described in more detail under "Risk Factors" in Items 1. and 2. "Business and Properties" located elsewhere in this Form 10-K.

Item 8. Financial Statements and Supplementary Data

REPORT OF MANAGEMENT

McMoRan Exploration Co. (McMoRan) is responsible for the preparation of the financial statements and all other information contained in this Annual Report. The financial statements have been prepared in conformity with accounting principles generally accepted in the United States and include amounts that are based on management's informed judgments and estimates.

McMoRan maintains a system of internal accounting controls designed to provide reasonable assurance at reasonable costs that assets are safeguarded against loss or unauthorized use, that transactions are executed in accordance with management's authorization and that transactions are recorded and summarized properly. The system was tested and evaluated on a regular basis through December 31, 2003 by McMoRan's internal auditors, PricewaterhouseCoopers LLP. McMoRan has appointed Deloitte & Touche LLP as its internal auditors effective January 1, 2004. In accordance with auditing standards generally accepted in the United States, McMoRan's independent public accountants, Ernst & Young LLP, have developed an overall understanding of our accounting and financial controls and have conducted other tests as they considered necessary to support their opinion on the financial statements.

The Board of Directors, through its Audit Committee composed solely of independent, non-employee directors, is responsible for overseeing the integrity and reliability of McMoRan's accounting and financial reporting practices and the effectiveness of its system of internal controls. Ernst & Young LLP and its internal auditors meet regularly with, and have access to, this committee, with and without management present, to discuss the results of their audit work.

Richard C. Adkerson	Glenn A. Klienert	Nancy D. Parmelee
Co-Chairman of the Board	President and	Senior Vice President,
	Chief Executive Officer	Chief Financial Officer and Secretary

REPORT OF INDEPENDENT AUDITORS

TO THE STOCKHOLDERS AND BOARD OF DIRECTORS OF McMoRan EXPLORATION CO.:

We have audited the accompanying consolidated balance sheets of McMoRan Exploration Co. (a Delaware Corporation) as of December 31, 2003 and 2002 and the related consolidated statements of operations, cash flow and changes in stockholders' deficit for each of the two years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. The Company's financial statements for the year ended December 31, 2001 were audited by other auditors who have ceased operations and whose report dated May 9, 2002 (except with respect to Note 10 as to which the date was June 7, 2002) included a reference to certain matters which, at that time, raised substantial doubt about the Company's ability to continue as a going concern.

We conducted our audits in accordance with auditing standards generally accepted in the 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 2003 and 2002 financial statements referred to above present fairly, in all material respects, the consolidated financial position of McMoRan Exploration Co. as of December 31, 2003 and 2002 and the consolidated results of its operations and its cash flow for years then ended in conformity with accounting principles generally accepted in the United States.

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."

/s/ Ernst & Young LLP

New Orleans, Louisiana
February 2, 2004

This is a copy of the audit report previously issued by Arthur Andersen LLP in connection with McMoRan Exploration Co.'s filing on Form 8-K reporting its results for the year ending December 31, 2001, reflecting the Company's sulphur operations on a discontinued operations basis. Arthur Andersen LLP has not reissued this audit report in connection with this filing on Form 10-K for the year ending December 31, 2003.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

TO THE STOCKHOLDERS AND BOARD OF DIRECTORS OF McMoRan EXPLORATION CO.:

We have audited the accompanying consolidated balance sheets of McMoRan Exploration Co. (a Delaware Corporation) as of December 31, 2001 and 2000 and the related consolidated statements of operations, cash flow and changes in stockholders' equity (deficit) for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the 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 financial position of McMoRan Exploration Co. as of December 31, 2001 and 2000 and the results of its operations and its cash flow for each of the three years in the period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States.

The accompanying financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Notes 1 and 10 to the financial statements, the Company has significant debt maturities and other obligations due in 2002 and it must obtain additional capital to fund these obligations and its oil and gas exploration activities. This raises substantial doubt about the Company's ability to continue as a going concern. Management's plans in regard to these matters are described in Note 10. The accompanying financial statements do not include any adjustments that might result from the outcome of these uncertainties.

Arthur Andersen LLP

New Orleans, Louisiana
May 9, 2002, (except with respect to
Note 10, as to which the date is
June 7, 2002)

McMoRan EXPLORATION CO.
CONSOLIDATED BALANCE SHEETS

	December 31, 2003	December 31, 2002
	(In Thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents:		
Continuing operations	$ 100,938	$ 12,907
Discontinued operations, $1.0 million and $0.9 million restricted at December 31, 2003 and 2002, respectively	961	2,316
Restricted investments (Note 1)	7,800	-
Accounts receivable:		
Customers	2,328	3,456
Joint interest partners	311	348
Other	3,667	9,841
Prepaid expenses and product inventories	1,053	911
Current assets from discontinued operations, excluding cash	417	449
Total current assets	117,475	30,228
Property, plant and equipment, net (Note 4)	26,185	37,895
Discontinued sulphur business assets	312	355
Restricted investments and cash (Note 1)	18,974	-
Other assets	6,334	3,970
Total assets	$ 169,280	$ 72,448
LIABILITIES AND STOCKHOLDERS' DEFICIT		
Current liabilities:		
Accounts payable	$ 5,345	$ 5,246
Accrued liabilities	12,894	5,092
Accrued interest	3,900	-
Current portion of accrued reclamation costs for Main Pass facilities (Note 4)	2,550	8,126
Current portion of accrued reclamation costs for oil and gas facilities	238	878
Other current liabilities from discontinued operations	9,405	5,481
Other	-	328
Total current liabilities	34,332	25,151
6% Convertible Senior Notes (Note 5)	130,000	-
Accrued oil and gas reclamation costs	7,035	7,116
Accrued sulphur reclamation costs	11,451	30,421
Contractual postretirement obligation related to discontinued operations	22,034	21,564
Other long-term liabilities (Note 4)	18,435	18,854
Commitments and contingencies (Note 11)		
Mandatorily redeemable convertible preferred stock, net of unamortized offering costs of $1.2 million (Note 6)	30,586	33,773
Stockholders' equity (deficit):		
Preferred stock, par value $0.01, 50,000,000 shares authorized and unissued	-	-
Common stock, par value $0.01, 150,000,000 shares authorized, 19,181,251 shares and 18,429,402 shares issued and outstanding, respectively	192	184
Capital in excess of par value of common stock	319,530	307,903
Unamortized value of restricted stock units	(955)	(151)
Accumulated deficit	(360,688)	(329,770)
Common stock held in treasury, 2,302,068 shares and 2,295,900 shares, at cost, respectively	(42,672)	(42,597)
Stockholders' deficit	(84,593)	(64,431)
Total liabilities, convertible preferred stock and stockholders' deficit	$ 169,280	$ 72,448

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

McMoRan EXPLORATION CO.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2003	2002	2001
	(In Thousands, Except Per Share Amounts)		
Revenues	$ 16,114	$ 43,768	$ 72,942
Costs and expenses:			
Production and delivery costs	7,116	26,223	35,016
Depletion, depreciation and amortization expense	14,112	24,117	65,868
Exploration expenses	14,109	13,259	61,831
General and administrative expenses	8,313	6,368	15,144
Start-up costs for Main Pass Energy Hub™ Project	11,411	-	-
Gain on disposition of oil and gas properties	-	(44,141)	-
Total costs and expenses	55,061	25,826	177,859
Operating income (loss)	(38,947)	17,942	(104,917)
Interest expense, net	(4,599)	(704)	(357)
Other income, net	1,700	1,313	481
Income (loss) from operations before provision for income taxes	(41,846)	18,551	(104,793)
Provision for income taxes	(1)	(7)	(8)
Income (loss) from continuing operations	(41,847)	18,544	(104,801)
Loss from discontinued operations	(11,233)	(503)	(43,260)
Net income (loss) before cumulative effect of change in accounting principle	(53,080)	18,041	(148,061)
Cumulative effect of change in accounting principle	22,162	-	-
Net income (loss)	(30,918)	18,041	(148,061)
Preferred dividends and amortization of convertible preferred stock issuance costs	(1,738)	(1,000)	-
Net income (loss) applicable to common stock	$ (32,656)	$ 17,041	$ (148,061)
Net income (loss) per share of common stock:			
Basic net income (loss) from continuing operations	$(2.62)	$1.09	$(6.60)
Basic net loss from discontinued operations	(0.68)	(0.03)	(2.73)
Before cumulative effect of change in accounting principle	(3.30)	1.06	(9.33)
Cumulative effect of change in accounting principle	1.33	-	-
Basic net income (loss) per share of common stock	$(1.97)	$1.06	$(9.33)
Diluted net income (loss) from continuing operations	$(2.62)	$0.93	$(6.60)
Diluted net loss from discontinued operations	(0.68)	(0.02)	(2.73)
Before cumulative effect of change in accounting principle	(3.30)	0.91	(9.33)
Cumulative effect of change in accounting principle	1.33	-	-
Diluted net income (loss) per share of common stock	$(1.97)	$0.91	$(9.33)
Average common shares outstanding:			
Basic	16,602	16,010	15,869
Diluted	16,602	19,879	15,869

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

McMoRan EXPLORATION CO.
CONSOLIDATED STATEMENTS OF CASH FLOW

	2003	2002	2001
	Years Ended December 31, (In Thousands)		
Cash flow from operating activities:			
Net income (loss)	$ (30,918)	$ 18,041	$ (148,061)
Adjustments to reconcile net income (loss) to net cash used in operating activities:			
Loss from discontinued operations	11,233	503	43,260
Depletion, depreciation and amortization	14,112	24,117	65,868
Exploration drilling and related expenditures	8,823	9,097	43,510
Cumulative effect of change in accounting principle	(22,162)	-	-
Stock warrants granted – Main Pass Energy Hub™	6,220	-	-
Compensation associated with stock-based awards	2,201	-	-
Amortization of deferred financing costs	698	-	-
Gain on disposition of oil and gas properties	-	(44,141)	-
Gain on sale of equity investment	-	(1,084)	-
Changes in assets and liabilities:			
Reclamation and mine shutdown expenditures	(699)	(752)	(2,196)
Other	(307)	1,854	2,149
(Increase) decrease in working capital:			
Accounts receivable	287	4,079	6,090
Accounts payable and accrued liabilities	7,324	(19,019)	(3,772)
Inventories and prepaid expenses	(142)	211	(222)
Net cash provided by (used in) continuing operations	(3,330)	(7,094)	6,626
Net cash used in discontinued sulphur operations	(10,769)	(11,567)	(14,752)
Net cash used in operating activities	(14,099)	(18,661)	(8,126)
Cash flow from investing activities:			
Exploration, development and other capital expenditures	(5,523)	(16,984)	(107,092)
Purchase of restricted investments	(22,928)	-	-
Increase in restricted investments	(127)	-	-
Proceeds from disposition of oil and gas properties	7,050	63,400	1,291
Net cash provided by (used in) continuing activities	(21,528)	46,416	(105,801)
Net cash provided by discontinued sulphur operations	189	58,583	6,252
Net cash provided by (used in) investing activities	(21,339)	104,999	(99,549)
Cash flow from financing activities:			
Proceeds from issuance of 6% convertible senior notes	130,000	-	-
Financing costs	(7,032)	-	-
Net borrowings (repayments) on oil and gas credit facility	-	(49,657)	49,657
Net proceeds from preferred stock offering	-	33,698	-
Dividends paid on convertible preferred stock	(1,631)	(924)	-
Proceeds from exercise of stock options and other	777	268	612
Net cash (used in) provided by continuing operations	122,114	(16,615)	50,269
Net borrowings (repayments) on sulphur credit facility	-	(55,000)	9,000
Net cash provided by (used in) financing activities	122,114	(71,615)	59,269

	Years Ended December 31,		
	2003	2002	2001
		(In Thousands)	
Net increase (decrease) in cash and cash equivalents	86,676	14,723	(48,406)
Net increase in restricted cash of discontinued operations	(20)	(941)	-
Net increase (decrease) in unrestricted cash and cash equivalents	86,656	13,782	(48,406)
Cash and cash equivalents at beginning of year	14,282	500	48,906
Cash and cash equivalents at end of year	$ 100,938	$ 14,282	$ 500
Interest paid	$ 2	$ 4,027	$ 6,973
Income taxes paid	$ 1	$ 7	$ 8

The accompanying notes, which include information in Notes 1, 3, 4, 7, 8, 10, and 14 regarding noncash transactions, are an integral part of these consolidated financial statements.

McMoRan EXPLORATION CO.
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' DEFICIT
(In thousands, except share amounts)

	Years Ended December 31,		
	2003	2002	2001
Preferred stock:			
Balance at beginning and end of year	$ -	$ -	$ -
Common stock:			
Balance at beginning of year representing 18,429,402 shares in 2003, 18,194,139 shares in 2002, and 18,138,875 shares in 2001	184	182	181
Exercised stock options representing 51,119 shares in 2003, no shares in 2002, and 3,724 shares in 2001	1	-	-
Shares issued to CLK (Note 11) representing no shares in 2003, 235,263 shares in 2002 and 51,540 shares in 2001	-	2	1
Mandatorily redeemable preferred stock conversions representing 684,063 shares in 2003 and no shares in 2002 and 2001	7	-	-
Balance at end of year representing 19,181,251 shares in 2003, 18,429,402 shares in 2002 and 18,194,139 shares in 2001	192	184	182
Capital in Excess of Par Value:			
Balance at beginning of year	307,903	302,454	301,343
Mandatorily redeemable preferred stock conversions	3,287	-	-
Exercised stock options and other (Note 8)	2,607	268	612
Shares issued to CLK	-	934	499
Restricted stock unit grants	1,251	194	-
Issuance of stock warrants (Note 4)	6,220	5,053	-
Dividends on preferred stock and amortization of issuance cost	(1,738)	(1,000)	-
Balance at end of year	319,530	307,903	302,454
Unamortized value of restricted stock units:			
Balance beginning of year	(151)	-	-
Deferred compensation associated with restricted stock units (Note 1)	(1,251)	(194)	-
Amortization of related deferred compensation	447	43	-
Balance end of year	(955)	(151)	-
Accumulated Deficit:			
Balance at beginning of year	(329,770)	(347,811)	(199,750)
Net income (loss)	(30,918)	18,041	(148,061)
Balance at end of year	(360,688)	(329,770)	(347,811)
Accumulated other comprehensive loss:			
Balance at beginning of year	-	-	-
Other comprehensive loss:			
Cumulative effect of changes in accounting for derivatives	-	-	(492)
Change in unrealized derivatives' fair value	-	-	(177)
Reclass to earnings	-	-	669
Balance at end of year	-	-	-
Common Stock Held in Treasury:			
Balance at beginning of year representing 2,295,900 shares in 2003, 2002 and 2001	(42,597)	(42,597)	(42,597)
Tender of 6,168 shares in 2003 to exercise McMoRan stock options	(75)	-	-
Balance at end of year representing 2,302,068 shares in 2003 and 2,295,900 shares in 2002 and 2001	(42,672)	(42,597)	(42,597)
Total stockholders' deficit	$ (84,593)	$ (64,431)	$ (87,772)

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation. The consolidated financial statements of McMoRan Exploration Co. (McMoRan), a Delaware Corporation, include the accounts of those subsidiaries where McMoRan directly or indirectly has more than 50 percent of the voting rights and for which the right to participate in significant management decisions is not shared with other shareholders. McMoRan consolidates its wholly owned McMoRan Oil & Gas LLC (MOXY) and Freeport-McMoRan Energy LLC (Freeport Energy) subsidiaries and reflects its investment in K-Mc Venture I LLC (K-Mc I) using the equity method (Note 4). Investments in other oil and gas joint ventures and partnerships in which McMoRan owns an undivided interest in the underlying assets are proportionately consolidated in the accompanying financial statements. All significant intercompany transactions have been eliminated. Certain prior year amounts have been reclassified to conform to the current year presentation. Changes in the accounting principles applied during the years presented are discussed below under the caption "Accounting Change –Reclamation and Closure Costs" and "New Accounting Standards."

In connection with its efforts to establish an energy hub at Main Pass Block 299 (Main Pass) (Note 3), Freeport Energy changed its name from Freeport-McMoRan Sulphur LLC (Freeport Sulphur) in 2003. As a result of McMoRan's exit from the sulphur business, as evidenced by its sale of substantially all of its sulphur assets (Note 7), its sulphur results have been presented as discontinued operations and the major classes of assets and liabilities related to the sulphur business held for sale have been separately shown for all periods presented.

Use of Estimates. The preparation of McMoRan's financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts reported in these consolidated financial statements and the accompanying notes. The more significant estimates include useful lives for depletion, depreciation and amortization, reclamation and environmental obligations, the carrying value of long-lived assets and assets held for sale or disposal, postretirement and other employee benefits, valuation allowances for deferred tax assets, and estimates of proved oil and gas reserves and related future cash flows. Actual results could differ from those estimates.

Cash and Cash Equivalents. Highly liquid investments purchased with an original maturity of three months or less are considered cash equivalents (excluding restricted cash, see Note 7).

Accounts Receivable. Other accounts receivable include proceeds owed to McMoRan associated with the sale of its Main Pass oil producing assets to K-Mc I in December 2002 (Note 4). Amounts outstanding on this receivable were $2.6 million at December 31, 2003, and $9.6 million at December 31, 2002.

Inventories. Inventories are stated at the lower of average cost or market. McMoRan was required to reduce its sulphur product inventory carrying costs to its then net realizable value on two separate occasions during 2001. These charges, included within the caption "Loss from discontinued operations", totaled $10.0 million (Note 7).

Property, Plant and Equipment.

Oil and Gas. McMoRan follows the successful efforts method of accounting for its oil and gas exploration and development activities. Geological and geophysical costs and costs of retaining unproved properties are charged to expense as incurred and are included as a reduction of operating cash flow in the accompanying consolidated statements of cash flow. Costs of exploratory wells are capitalized pending determination of whether they have discovered proved reserves. If proved reserves are not discovered the related drilling costs are charged to exploration expense. Acquisition costs of leases and development activities are also capitalized. Costs associated with drilling and development activities are included as a reduction of investing cash flow in the accompanying consolidated statements of cash flow. Other exploration costs are charged to expense as incurred. Depletion, depreciation and amortization expense is determined on a field-by-field basis using the units-of-production method based on estimated proved and proved developed reserves associated with each field. Gains or losses are included in earnings when properties are sold and there are no related substantial future obligations retained.

Interest expense allocable to significant unevaluated leasehold costs and in progress exploration and development projects is capitalized until the assets are ready for their intended use. Interest expense capitalized by McMoRan totaled $0.3 million during 2002 and $1.5 million during 2001. No interest was capitalized during 2003.

Sulphur. McMoRan's remaining sulphur property, plant and equipment is carried at the lower of cost or estimated net realizable value of the assets. In June 2002, Freeport Sulphur sold substantially all of its assets to a joint venture, receiving $58.0 million in gross proceeds in the sales transaction (Note 7).

During the fourth quarter of 2001, McMoRan recorded a $10.8 million charge to reduce its sulphur transportation and terminaling assets to their estimated net realizable values. See Note 7 for more discussion regarding McMoRan's sulphur-related charges now included in the accompanying consolidated statements of operations within the caption "Loss from discontinued operations."

Asset Impairment. Costs of unproved oil and gas properties are assessed periodically and a loss is recognized if the properties are deemed impaired, which could occur if management decides against drilling at a certain lease or if the lease expires in the near-term. When events or circumstances indicate that proved oil and gas property carrying amounts might not be recoverable from estimated future undiscounted cash flows from the property, a reduction of the carrying amount to fair value is required. Measurement of the impairment loss is based on the estimated fair value of the asset, which McMoRan generally determines using estimated undiscounted future cash flows from the property, adjusted to present value using an interest rate considered appropriate for the asset. Future cash flow estimates for McMoRan's oil and gas properties are measured on a field-by-field basis and include future estimates of proved and risk-adjusted probable reserves, oil and gas prices, production rates and operating, development and reclamation costs based on operating budget forecasts. Assumptions underlying future cash flow estimates are subject to various risks and uncertainties, some of which are beyond McMoRan's control.

In second quarter of 2003, McMoRan charged to exploration expense the remaining $4.0 million of leasehold costs associated with the Hornung prospect, which covers four offshore lease blocks (Eugene Island Blocks 96/97/108/109), following the expiration of two of the leases. At December 31, 2003, following a downward revision of the estimated proved reserves for the Vermilion Block 160 field, McMoRan recorded a $3.9 million impairment charge to depletion, depreciation and amortization expense to reduce the field's carrying cost to its estimated fair value at that date.

At December 31, 2002, as a result of a reduction in the estimated proved reserves for its Eugene Island Block 97 field, McMoRan recorded an impairment charge to depletion, depreciation and amortization expense totaling $4.4 million to reduce the field's net book value to its estimated fair value at that date. In the third quarter of 2002, the West Cameron Block 624 field ceased production and McMoRan recorded a $3.2 million impairment charge to depletion, depreciation and amortization expense to write-off the remaining asset carrying cost of the field. In October 2002, the initial Hornung prospect exploratory well at Eugene Island Block 108 was evaluated not to contain commercial quantities of hydrocarbons and was plugged and abandoned. As a result, McMoRan recorded a $5.3 million charge to exploration expense to impair a portion of its leasehold acquisition costs associated with the Hornung prospect.

At December 31, 2001, McMoRan recorded a $23.2 million charge to depletion, depreciation and amortization expense that reduced the net book values of the West Cameron Block 616 field by $19.1 million and the West Cameron Block 624 field by $4.1 million to their then estimated fair values. In addition, McMoRan recorded a $15.9 million charge to depletion, depreciation and amortization expense to impair the carrying amount for the Louisiana State Lease 340 No. 2 well following unsuccessful attempts to re-establish production from the well in early 2001.

Restricted investments and cash. Restricted investments and cash totaled $26.8 million at December 31, 2003, including $7.8 million classified as current . McMoRan's restricted investments include U.S. government securities, plus accrued interest thereon, pledged as security for scheduled interest payments through July 2, 2006, on McMoRan's outstanding 6% Convertible Senior Notes (Note 5). McMoRan's restricted cash includes $3.5 million of escrowed funds for certain assumed environmental liabilities (Note 11). McMoRan has $1.0 million of restricted cash associated with its discontinued sulphur operations (Note 7).

Revenue Recognition. Revenue for the sale of crude oil and natural gas is recognized when title passes to the customer. Natural gas revenues involving partners in natural gas wells are recognized when the gas is sold using the entitlements method of accounting and are based on McMoRan's net revenue interests. For all periods presented both the quantity and dollar amount of gas balancing arrangements were immaterial.

Major Customers. McMoRan sales of its oil and gas production to major customers totaled approximately 85 percent to two purchasers in 2003, approximately 90 percent to three purchasers in 2002 and approximately 70 percent two customers in 2001. Freeport Sulphur sold approximately 93 percent of its sulphur to one customer in 2001. All of McMoRan's customers are located in the United States.

Accounting Change - Reclamation and Closure Costs. McMoRan incurs costs for environmental programs and projects. Expenditures pertaining to future revenues from operations are capitalized. Expenditures resulting from the remediation of conditions caused by past operations that do not contribute to future revenue generation are charged to expense. Liabilities are recognized for remedial activities when the efforts are probable and the costs can be reasonably estimated. Reclamation cost estimates are by their nature imprecise and can be expected to be revised over time because of a number of factors, including changes in reclamation plans, cost estimates, governmental regulations, technology and inflation (Note 11).

Effective January 1, 2003, McMoRan adopted Statement of Accounting Standards No. 143 (SFAS 143), "*Accounting for Asset Retirement Obligations*," which requires recording the fair value of an asset retirement obligation associated with tangible long-lived assets in the period incurred. Retirement obligations associated with long-lived assets included within the scope of SFAS 143 are those for which there is a legal obligation to settle under existing or enacted law, statute, written or oral contract or by legal construction under the doctrine of promissory estoppel. McMoRan recorded a gain of $22.2 million representing the cumulative effect of a change in accounting principle from the adoption of this standard.

McMoRan used estimates prepared by third parties in determining its January 1, 2003 estimated asset retirement obligations under multiple probability scenarios reflecting a range of possible outcomes considering the future costs to be incurred, the scope of work to be performed and the timing of such expenditures. Using this approach, the estimated retirement obligations associated with McMoRan's oil and gas operations was $9.8 million and for its former sulphur operations approximated $32.3 million. The total of these estimates is less than the estimates on which the obligations were previously accrued because of the effect of applying weighted probabilities to the multiple scenarios used in this calculation lower than the most probable case, which was the basis of the previous accrual. To calculate the fair value of the estimated obligations, McMoRan applied an estimated long-term inflation rate of 2.5 percent and a market risk premium of 10 percent, which was based on market-based estimates of rates that a third party would have to pay to insure its exposure to possible future increases in the costs of these obligations. McMoRan discounted the resulting projected cash flows at our estimated credit-adjusted, risk-free interest rates, which ranged from 4.6 percent to 10 percent, for the corresponding time periods over which these costs would be incurred. See Note 11 for information regarding revisions to these estimates at December 31, 2003.

Prior to adoption of SFAS 143, McMoRan accrued its estimated future expenditures to restore its oil and gas properties and related facilities to a condition that it believes complies with environmental and other regulations over the life of the properties using the units-of-production method based on estimated proved reserves of each respective field. At December 31, 2002, McMoRan had $8.0 million of accrued oil and gas reclamation costs, including $0.9 million of current obligations. In December 2002, after the disposition of the Main Pass oil interests, McMoRan reduced its accrued oil and gas reclamation obligations by $9.4 million (Note 4). The reclamation obligations related to each of McMoRan's closed sulphur mines and related facilities were previously fully accrued upon their closure. At December 31, 2002, McMoRan had $38.5 million of accrued sulphur reclamation costs, including $8.1 million of current obligations. See Note 7 for a discussion of McMoRan's Turnkey Contracts that reduced McMoRan's accrued sulphur reclamation obligations by $25.4 million in 2002.

Pro Forma Net Income (Loss) Presented below are McMoRan's reported results and pro forma amounts that would have been reported in McMoRan's Consolidated Statements of Operations had these statements been adjusted for the retroactive application of SFAS 143 (in thousands, except per share amounts):

	2003	2002	2001
Actual reported results:			
Net income (loss) from continuing operations	$ (41,847)	$ 18,544	$ (104,801)
Net income (loss) applicable to common stock	(32,656)	17,041	(148,061)
Basic net income (loss) of common stock from continuing operations	(2.62)	1.09	(6.60)
Basic net income (loss) per share of common stock	(1.97)	1.06	(9.33)
Diluted net income (loss) of common from continuing operations	(2.62)	0.93	(6.60)
Diluted net income (loss) per share of common stock	(1.97)	0.91	(9.33)
Pro forma amounts assuming retroactive application:			
Net income (loss) from continuing operations	$ (41,847)	$ 17,660	$ (106,207)
Net income (loss) applicable to common stock	(54,818)	15,392	(150,175)
Basic net income per share of common stock from continuing operations	(2.62)	1.10	(6.69)
Basic net income (loss) per share of common stock	(3.30)	0.96	(9.46)
Diluted net income per share of common stock from continuing operations	(2.62)	0.89	(6.69)
Diluted net income per share of common stock	(3.30)	0.77	(9.46)

Financial Instruments and Contracts. Based on its assessment of market conditions, McMoRan may enter into financial contracts to manage certain risks resulting from fluctuations in oil and natural gas prices. McMoRan accounts for financial contracts and other derivatives pursuant to SFAS No. 133 *"Accounting for Derivative Instruments and Hedging Activities."* Under this standard, costs or premiums and gains or losses on contracts meeting deferral criteria are recognized with the hedged transactions. Also, gains or losses are recognized if the hedged transaction is no longer expected to occur or if deferral criteria are not met. McMoRan monitors its credit risk on an ongoing basis and considers this risk to be minimal. The adoption of SFAS 133 did not significantly affect McMoRan's financial statements in 2001.

McMoRan's use of financial contracts to manage risks has been limited. McMoRan had no financial contracts during 2003 or 2002. McMoRan's only contracts during 2001 involved forward sales contracts for oil produced at Main Pass, which were entered into considering the required level of production costs at the field. McMoRan settled forward sales contracts covering 0.1 million barrels of oil at a cost of $0.7 million during 2001. These costs reduced McMoRan's oil revenues for 2001. McMoRan currently has no forward oil sales contracts or other derivative contracts.

Share Purchase Program. McMoRan's Board of Directors has authorized an open market share purchase program for up to 2.5 million shares of its common stock. McMoRan did not purchase any shares of its common stock during the three year period ending December 31, 2003. As of December 31, 2003, McMoRan had purchased 2,244,635 shares of its common stock at an average cost of $18.56 per share.

Restricted Stock. Under McMoRan's stock-based compensation plans (Note 8), the Board of Directors granted 50,000 restricted stock units (RSUs) in April 2002 and 100,000 RSUs in May 2003 that will be converted ratably into an equivalent number of shares of McMoRan common stock on the grant anniversary dates over the next three years. Upon issuance of the RSUs, unearned compensation equivalent to the market value at the date of grants, totaling approximately $0.2 million for the grant in April 2002 and $1.3 million for the grant in May 2003, was recorded as deferred compensation in stockholders' equity and is charged to expense over the three-year period. McMoRan charged approximately $0.4 million of this deferred compensation to expense during 2003 and $43,000 in 2002.

Earnings Per Share. Basic net income (loss) per share of common stock was calculated by dividing the income (loss) applicable to continuing operations, loss from discontinued operations, cumulative effect of change in accounting principle and net income (loss) applicable to common stock by the weighted-average number of common shares outstanding during the periods presented. For purposes of the basic earnings per share computations, net income (loss) applicable to continuing operations includes preferred stock dividends and related charges. The following is a reconciliation of net income (loss) and weighted average common shares outstanding for purposes of calculating diluted net income (loss) per share (in thousands, except per share amounts):

	Year Ended December 31,		
	2003	2002	2001
Basic income (loss) from continuing operations	$(43,585)	17,544	(104,801)
Add: Preferred dividends and issuance cost amortization from assumed conversion	-	1,000	-
Diluted income (loss) from continuing operations	(43,585)	18,544	(104,801)
Loss from discontinued operations	(11,233)	(503)	(43,260)
Net income (loss) before cumulative effect of change in accounting principle	(54,818)	18,041	(148,601)
Cumulative effect of change in accounting principle	22,162	-	-
Diluted net income (loss) applicable to common stock	$ (32,656)	$ 18,041	$ (148,061)
Weighted average common shares outstanding	16,602	16,010	15,869
Dilutive stock options [a]	-	1	-
Assumed conversion of preferred stock [b]	-	3,868	-
Weighted average common shares outstanding for purposes of calculating diluted net income (loss) per share	16,602	19,879	15,869
Diluted net income (loss) from continuing operations	$(2.62)	$0.93	$(6.60)
Diluted net income (loss) from discontinued operations	(0.68)	(0.02)	(2.73)
Before cumulative effect of change in accounting principle	(3.30)	0.91	(9.33)
Cumulative effect of change in accounting principle	1.33	-	-
Diluted net income (loss) per share	$(1.97)	$0.91	$(9.33)

a. Excludes options that otherwise would have been included in the diluted per share calculation but would make the calculations anti-dilutive considering the net loss incurred during the periods. Excluded options represented 539,000 shares in 2003 and 126,000 shares in 2001.
b. Assumes the conversion of the 1.4 million shares of 5% convertible preferred stock into approximately 7.3 million shares of McMoRan common stock (Note 6). The effect of the assumed conversion during the period from the issuance date (June 21, 2002) to December 31, 2002 (194 days) equates to approximately 3.9 million shares of McMoRan common stock. During 2003, the assumed conversion of the convertible preferred stock into approximately 6.6 million shares of McMoRan common stock was excluded in the earnings per share calculation considering the anti-dilutive impact on the loss from continuing operations during the period.

Outstanding stock options with exercise prices greater than the average market price of the common stock during the year are excluded from the computation of diluted net income (loss) per share of common stock. In addition, stock warrants issued to a third party (Note 4) and McMoRan's 6% Convertible Senior Notes (Note 5) are excluded from the computation of diluted net income (loss) per share of common stock during the years show below because including the assumed conversion of these instruments would have decreased reported net loss per share. The stock warrants were excluded from the 2002 calculation because the exercise price of the warrants exceeded the average market price of McMoRan's common stock. Accrued interest related to the Convertible Senior Notes totaled $3.9 million at December 31, 2003. The excluded amounts are summarized below (in thousands, except exercise prices):

	Years Ended December 31,		
	2003	2002	2001
Outstanding options (in thousands)	2,607	3,368	1,318
Average exercise price	$ 16.92	$ 14.86	$ 17.44
Shares issuable upon exercise of stock warrants	2,500	1,740	N/A
Shares issuable upon assumed conversion of 6% Convertible Senior Notes	9,123	N/A	N/A

Stock-Based Compensation Plans. As of December 31, 2003, McMoRan has five stock-based employee and director compensation plans, which are described in Note 8. McMoRan accounts for those plans under the recognition and measurement principles of Accounting Principles Board (APB) Opinion No. 25, "*Accounting for Stock Issued to Employees*," and related interpretations. The following table illustrates the effect on net income (loss) and earnings per share if McMoRan had applied the fair value recognition provisions of SFAS 123, "*Accounting for Stock-Based Compensation*," to all stock-based employee compensation (in thousands, except per share amounts).

	Years Ended December 31,		
	2003	2002	2001
Basic net income (loss) applicable to common stock, as reported	$ (32,656)	$ 17,041	$ (148,061)
Add: Stock-based employee compensation expense recorded in net income for restricted stock units and employee stock options	2,201	43	-
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards	(7,199)	(5,166)	(3,276)
Pro forma basic net income (loss) applicable to common stock	(37,654)	11,918	(151,337)
Add: preferred dividends and issuance cost amortization from assumed conversion	-	1,000	-
Pro forma diluted net income (loss) applicable to common stock	$ (37,654)	$ 12,918	$ (151,337)
Earnings (loss) per share:			
Basic – as reported	$ (1.97)	$ 1.06	$ (9.33)
Basic – pro forma	$ (2.27)	$ 0.74	$ (9.54)
Diluted – as reported	$ (1.97)	$ 0.91	$ (9.33)
Diluted – pro forma	$ (2.27)	$ 0.65	$ (9.54)

For the pro forma computations, the values of the option grants were calculated on the dates of grant using the Black-Scholes option-pricing model. The pro forma effects on net income are not representative of future years because of the potential changes in the factors used in calculating the Black-Scholes valuation and the number and timing of option grants. No other discounts or restrictions related to vesting or the likelihood of vesting of stock options were applied. The table below summarizes the weighted average assumptions used to value the options under SFAS 123.

	Years Ended December 31,		
	2003	2002	2001
Fair value of stock options	$ 8.14	$ 3.16	$ 11.38
Risk free interest rate	3.6%	5.1%	5.3%
Expected volatility rate	66%	55%	55%
Expected life of options (in years)	7	7	10
Assumed annual dividend	-	-	-

New Accounting Standards. As discussed in "Accounting Change - Reclamation and Closure Costs" above, McMoRan adopted SFAS No. 143 on January 1, 2003. In May 2003, the Financial Accounting Standards Board issued No. 150, *"Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity."* The new standard was effective July 1, 2003. The new standard currently does not affect McMoRan because its 5% convertible preferred stock is convertible at the option of the holder at any time through maturity, qualifying it to retain its historical classification

In January 2003, the FASB issued Interpretation No. 46, *"Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin (ARB) No. 51,"* which addresses consolidation of variable interest entities. In October 2003, the required implementation date of this interpretation was deferred to the fourth quarter of 2003, for variable interest entities acquired before February 1, 2003. Effective December 31, 2003, McMoRan adopted the provisions of Interpretation No. 46. The implementation of the statement did not have any impact on McMoRan's consolidated financial statements.

In August 2001, the FASB issued SFAS No. 144, *"Accounting for the Impairment or Disposal of Long-Lived assets"*, which supersedes FASB No. 121, *"Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of."* SFAS No. 144 also supersedes certain aspects of APB Opinion No. 30, *"Reporting the Results of Operations - Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions,"* with regard to reporting the effects of a disposal of a segment of a business and requires expected future operating losses from discontinued operations to be separately reported in the period incurred rather than at the measurement date as formerly required by APB 30. Additionally, certain asset dispositions previously not qualifying for discontinued operations treatment may now be required to be presented in this manner. The statement was effective for fiscal years beginning after December 15, 2001. McMoRan adopted this new standard on January 1, 2002 and has reflected its former sulphur operations as discontinued operations for all periods presented as discussed in "Basis of Presentation" above.

2. OIL & GAS EXPLORATION ACTIVITIES

McMoRan currently has one operating segment, Oil and Gas. McMoRan's oil and gas operations are conducted through MOXY, whose operations and properties are located almost exclusively offshore on the continental shelf in the Gulf of Mexico. McMoRan also owns 33.3 percent of a joint venture that operates the oil facilities at Main Pass. Additional information regarding McMoRan's oil and gas operations is included below.

Acreage

McMoRan acquired a significant portion of its current exploration acreage through the completion of two transactions in early 2000. The first was a farm-in transaction whereby McMoRan had the right to explore and earn assignment of operating rights to an approximate 400,000 gross-acre position from Texaco Exploration and Production Inc. (Texaco), now a subsidiary of ChevronTexaco Corp. The second transaction was the purchase of 55 exploration leases from Shell Offshore Inc. (Shell), a wholly owned subsidiary of Royal Dutch Petroleum Co for $37.8 million. Acreage acquired through these transactions are located in water depths ranging from 10 feet to 2,600 feet in federal and state waters offshore Louisiana and Texas, with most of the acreage located in waters of less than 400 feet.

The Texaco exploration agreement expired on January 1, 2004, at which time McMoRan's right to continue to identify prospects and drill to earn leasehold interests not previously earned expired, except for those properties as to which McMoRan had committed to drill an exploration well or otherwise received an extension from Texaco. On January 1, 2004, McMoRan retained rights or interests in six leases covering approximately 31,500 gross acres and 12,200 net acres related to the Texaco agreement. McMoRan will retain its rights in these leases as long as it commences, or commits to, drilling activities on or before June 30, 2004. McMoRan met all of its requirements under the Texaco exploration agreement to incur or commit to incur a minimum of $110 million of exploration expenditures on these properties by June 30, 2003 (Note 11).

A summary of McMoRan's approximate acreage position is included below

	Number of Leases	Gross Acres	Net Acres
At January 1, 2004	52	201,000	95,000

No leases related to McMoRan's JB Mountain prospect at South Marsh Island Block 223 or at its Mound Point prospect at Louisiana State Lease 340 have near-term expirations, although additional drilling will be required to maintain McMoRan's rights to portions of this acreage and approximately 17,000 acres in the Lighthouse Point area was relinquished to the State of Louisiana in February 2004. McMoRan can retain its exploration rights to the above referenced acreage by conducting successful exploration activities on the leases.

Exploration Funding Arrangements

In May 2002, MOXY entered into a farm-out agreement with El Paso Production Company (El Paso) that provides for the funding of exploratory drilling and related development costs with respect to four of its prospects in the shallow waters of the Gulf of Mexico. Under the program, El Paso is funding all of MOXY's interests for the exploratory drilling and development costs of these prospects and will own 100 percent of the program's interests in the four prospects until aggregate production to the program's net revenue interests reaches 100 Bcfe. After aggregate production of 100 Bcfe, ownership of 50 percent of the program's interests would revert back to MOXY. The four prospects in the exploration arrangement are "Hornung" at Eugene Island Block 108, "JB Mountain" at South Marsh Island Block 223, "Lighthouse Point- Deep" at South Marsh Island Block 207 and "Mound Point Offset" at Louisiana State Lease 340. The JB Mountain and Lighthouse Point – Deep prospects are both located within federal lease OCS 310. McMoRan announced the initial discoveries at the JB Mountain prospect in December 2002 and the Mound Point prospect in April 2003. El Paso elected to relinquish its rights to both the Hornung and Lighthouse Deep prospects following nonproductive exploratory wells being drilled at each of these prospects. There are three wells currently producing under this farm-out program and two additional wells are currently being drilled, one each at the JB Mountain and Mound Point.

McMoRan intends to significantly increase its exploration drilling activities during 2004 (Note 12). McMoRan will use its $100.9 million of unrestricted cash at December 31, 2003 and the projected revenues from production from its existing producing properties to fund its operations, near-term exploration activities and the costs associated with the pursuit of the energy hub at Main Pass (Note 3). As discussed in Note 12, McMoRan has recently entered into a multi-year exploration joint venture with a private exploration and production company, which has committed a minimum of $200 million towards exploration of McMoRan's inventory of prospects outside the JB Mountain and Mound Point prospect areas. McMoRan will incur similar exploration costs over the next several years. As a result, during this period McMoRan will need to develop additional financial resources and secure additional financing for its operations, including its exploration activities, through the discovery, development and production of oil and gas reserves, the identification and exploitation of new business opportunities involving Main Pass or otherwise obtain financing through other third parties.

3. MAIN PASS ENERGY HUB™ PROJECT

Freeport Energy has been pursuing alternative uses of its discontinued sulphur facilities at Main Pass in the Gulf of Mexico. Freeport Energy believes that an energy hub, consisting of facilities to receive and process liquefied natural gas (LNG) and store and distribute natural gas, could potentially be developed at the facilities using the infrastructure previously constructed for its former sulphur mining operations. Freeport Energy refers to this potential project as the Main Pass Energy Hub™ Project. Freeport Energy has completed conceptual and preliminary engineering for the project. As of December 31, 2003, Freeport Energy was preparing a license application to be filed with the U.S. Coast Guard that would authorize it to receive and process LNG and store and distribute natural gas at the facilities (Note 12). Previously Freeport Energy had filed for a permits that would allow it to use the Main Pass facilities as a disposal site for non-hazardous oilfield waste.

Freeport Energy is in the initial stages of determining the feasibility of developing an LNG terminal at the Main Pass facilities. Accordingly, it has not yet determined to develop the project. In addition to completing a detailed engineering and financial assessment, certain regulatory approvals are required and the project will require significant financing. Applying for regulatory permits and pursuing commercial arrangements will involve significant expenditures. Freeport Energy is seeking commercial arrangements to form the basis for financing the project. While there is no assurance that regulatory approvals and financing may be obtained at an acceptable cost, or on a timely basis, or at all, Freeport Energy's objective is to pursue both simultaneously in order to position this project to be one of the first U.S. offshore facilities to receive and process LNG and store and distribute natural gas. Freeport

Energy expects to spend approximately $15 million to advance the licensing process and to pursue commercial arrangements and financing for the project.

The start-up costs associated with the establishment of the Main Pass Energy Hub™ have been charged to expense in the accompanying consolidated statements of operations. During 2003, Freeport Energy incurred $11.4 million of start-up costs for the Main Pass Energy Hub™ Project, including a $6.2 million charge associated with the issuance of warrants representing 0.76 million shares of McMoRan common stock (Note 4).

Currently McMoRan owns 100 percent of the Main Pass Energy Hub™ Project. However, another party has the option to participate as a passive equity investor for up to 15 percent of Freeport Energy's equity interest in the Main Pass Energy Hub™ Project (Note 4). Financing arrangements may also reduce Freeport Energy's equity interest in the project.

4. PROPERTY, PLANT AND EQUIPMENT, OTHER ASSETS AND OTHER LIABILITIES

The components of net property, plant and equipment follow (in thousands):

	December 31, 2003	December 31, 2002
Oil and gas property, plant and equipment (Note 12)	$ 189,506	$ 184,700
Other	50	-
	189,556	184,700
Accumulated depletion, depreciation and amortization	(163,371)	(146,805)
Property, plant and equipment, net	$ 26,185	$ 37,895

Sales of Oil and Gas Properties

In February 2002, MOXY sold three of its proved oil and gas properties for $60.0 million. The sale was effective January 1, 2002. McMoRan sold its interests in Vermilion Block 196 and Main Pass Blocks 86/97, and 80 percent of its interests in Ship Shoal Block 296. McMoRan has retained its interests in exploratory prospects lying 100 feet below the stratigraphic equivalent of the deepest producing interval, at the time of the sale, at both Vermilion Block 196 and Ship Shoal Block 296. The properties were sold subject to a 75 percent reversionary interest after a defined payout, which would occur if and when the purchaser receives aggregate cumulative proceeds from the properties of $60.0 million plus an agreed annual rate of return. Currently two of the three properties sold in this transaction have production. Production has not yet commenced from Main Pass Blocks 86/97. At the time of the sale, McMoRan did not record any value associated with the reversionary interest because the estimated proved reserves associated with the related fields were deemed insufficient to achieve the defined payout amount. However, subsequent successful drilling and related enhanced production have increased the expected value of this reversionary interest, and at December 31, 2003, estimates of McMoRan's proved oil and gas reserves include certain associated reserve quantities (Note 13). Whether or not payout ultimately occurs depends primarily upon future production and future market prices of both natural gas and oil.

McMoRan used the proceeds from this transaction to fund a portion of its working capital requirements and to repay all borrowings under its oil and gas credit facility, which totaled $51.7 million in February 2002. The credit facility was then terminated (Note 5). McMoRan recorded a gain on the sale of its interests in these properties totaling $29.2 million.

Sale of Main Pass Oil Facilities to Joint Venture

In October 2002, McMoRan and K1 USA Ventures, Inc. and K1 USA Energy Production Corporation (K1 USA), subsidiaries of k1 Ventures Limited (collectively K1), a Singapore investment firm publicly traded on the Singapore Stock Exchange, formed an alliance to identify high-quality opportunities in the energy sector.

On December 16, 2002, McMoRan and K1 USA completed the formation of a joint venture, K-Mc I, which is owned 66.7 percent by K1 USA and 33.3 percent by McMoRan. K-Mc I acquired McMoRan's Main Pass oil facilities. In addition, upon McMoRan's request, K1 USA has agreed to provide credit support for up to $10 million of bonding requirements with the MMS relating to the abandonment obligations for these facilities. McMoRan continues to operate the Main Pass facilities under a management agreement. The facilities not required to support the future planned business activities that now comprise the Main Pass Energy Hub™ Project (Phase I), were excluded from the joint venture and their dismantlement and removal has been conducted pursuant to a Tunkey contract (Note 7). Proceeds for K-Mc I's acquisition of the Main Pass oil facilities are being funded in conjunction with McMoRan's funding requirements for the Phase I reclamation activities. See Note 11 for information concerning litigation between a third-party contractor and McMoRan regarding the rights and obligations of both parties under the reclamation arrangements.

During the fourth quarter of 2002, McMoRan recorded a $14.1 million gain associated with the formation of K-Mc I, which includes a $19.2 million gain on the sale of the Main Pass oil assets, including the elimination of its $9.4 million accrued reclamation obligation associated with the sold facilities, reduced by a $5.1 million charge for the value of the stock warrants issued to K1 USA (discussed below). The gain associated with the formation of K-Mc I is included within the caption "Gain on the disposition of oil and gas properties" in the accompanying consolidated statements of operations. McMoRan is accounting for its investment in the joint venture using the equity method (Note 1); however, McMoRan's investment (which had a zero basis at December 31, 2003 and 2002) is limited to exclude recognition of negative investment in K-Mc I as McMoRan is not required to fund K-Mc I's operating losses, debt or reclamation obligations.

Until September 2003, K-Mc I also had an option to acquire from McMoRan the Main Pass facilities that will be used in the potential Main Pass Energy Hub™ Project (Note 3). In September 2003, McMoRan and K1 USA modified the K-Mc I transaction to eliminate that option, so that K1 USA now has the right to participate as a passive equity investor in 15 percent of McMoRan's equity participation in the Main Pass Energy Hub™ Project. K1 USA would need to exercise that right upon closing of the project financing arrangements by agreeing prospectively to fund 15 percent of McMoRan's future contributions to the project. K1 USA has also received stock warrants to acquire a total of 2.5 million shares of McMoRan common stock at $5.25 per share, with the warrant for approximately 1.74 million shares expiring in December 2007 and the warrant for the remaining 0.76 million common shares expiring in September 2008. In connection with the warrants issued to K1 USA in September 2003, McMoRan recorded a charge of $6.2 million, which represented the fair value of the warrants determined using the Black-Scholes valuation method on the date of their issuance. This charge is included in "Start-up costs for Main Pass Energy Hub™ Project" in the accompanying consolidated statements of operations. Under terms of the modified agreement, McMoRan remains responsible for the potential supplemental bonding requirement related to the structures comprising the Main Pass Energy Hub™ Project. Previously, K1 USA would have been obligated to provide credit support of up to $10 million, if necessary, to cover the supplemental bonding requirements related to these facilities upon their election to participate in the project.

Other assets and liabilities
The components of other long-term liabilities follow (in thousands):

	December 31, 2003	December 31, 2002
Retiree medical liability (Note 8)	$ 4,674	$ 4,567
Accrued workers compensation and group insurance	2,976	3,131
Sulphur-related environmental liability (Note 11)	3,500	3,500
Defined benefit pension plan liability (Note 8)	1,617	1,964
Nonqualified pension plan liability	564	549
Deferred revenues, compensation and other	1,316	1,174
Liability for management services (Note 10)	3,233	3,233
Discontinued operations liabilities	555	736
	$ 18,435	$ 18,854

The caption "Other assets" in the accompanying consolidated balance sheet includes deferred financing costs associated with the issuance of $130 million of convertible debt in 2003 (Note 5). Issuance costs associated with the convertible debt totaled $7.0 million and are shown net of amortization $0.7 million at December 31, 2003.

5. LONG-TERM DEBT and CREDIT FACILITIES

6% Convertible Senior Notes
On July 3, 2003, McMoRan issued $130 million of 6% Convertible Senior Notes due July 2, 2008. Net proceeds from the notes totaled approximately $123.0 million, of which $22.9 million was used to purchase U.S. government securities held in escrow to secure the notes and to be used to pay the first six semi-annual interest payments. The notes are otherwise unsecured. Interest payments are payable on January 2 and July 2 of each year, beginning on January 2, 2004. The notes are convertible at the option of the holder at any time prior to maturity into shares of McMoRan's common stock at a conversion price of $14.25 per share, representing a 25 percent premium over the closing price for McMoRan's common stock on June 26, 2003.

McMoRan intends to use the approximate $100 million of net proceeds, excluding the interest reserve, for its near-term exploratory drilling activities; for possible opportunities to acquire interests in oil and gas properties or leases; for continuation of its efforts with respect to the Main Pass Energy Hub™ Project, including an LNG terminal and supporting facilities; and for working capital requirements and other corporate purposes.

Former Oil and Gas and Sulphur Credit Facilities

As part of a previous business arrangement with Halliburton Company (Halliburton), Halliburton provided a guarantee that initially provided up to $50 million of borrowings available to MOXY under a revolving oil and gas credit facility. The amount of this availability was reduced to $47.7 million in April 2001, when Halliburton elected to participate in McMoRan's Deep Tern prospect at Eugene Island Block 193. In February 2002, McMoRan sold certain of its oil and gas properties and used the related proceeds to repay the $47.7 million of borrowings outstanding under the guaranteed portion of its oil and gas credit facility and to terminate the Halliburton guarantee (Note 4).

McMoRan also had an additional $11.25 million of borrowing capacity under a separate portion of its oil and gas credit facility that was determined and secured by an oil and gas reserve borrowing base. Borrowings outstanding under this portion of the facility at the time it was terminated ($4.0 million) were also repaid in February 2002. The annualized average interest rate for the oil and gas credit facility was 2.6 percent in 2002 and 3.6 percent in 2001.

In addition to the oil and gas credit facility discussed above, McMoRan had a variable rate revolving credit facility available to Freeport Sulphur. Freeport Sulphur repaid all borrowings outstanding under this credit facility ($58.5 million) in June 2002 using the proceeds available from the sale of the sulphur transportation and terminaling assets (Note 7) and a portion of the proceeds generated by a public preferred stock offering (Note 6). The sulphur credit facility was then terminated. The annualized average interest rate for the sulphur facility was 6.7 percent in 2002 and 7.4 percent in 2001.

6. MANDATORILY REDEEMABLE PREFERRED STOCK

In June 2002, McMoRan completed a $35 million public offering of 1.4 million shares of its 5% mandatorily redeemable convertible preferred stock. Proceeds received from this offering totaled $33.7 million, net of an underwriting discount of $1.1 million and $0.2 million of other issuance costs. Each share provides for a quarterly cash dividend of $0.3125 per share ($1.25 per share annually) and is convertible at the option of the holder at any time into 5.1975 shares of McMoRan's common stock, which is equivalent to $4.81 per common share, representing a 20 percent premium over McMoRan's common stock closing price on June 17, 2002. During 2003, 131,615 shares of the convertible preferred stock were tendered and converted into approximately 0.7 million shares of McMoRan common stock. McMoRan may redeem the preferred stock after June 30, 2007 and must redeem the stock by June 30, 2012. Any redemption by McMoRan must be made in cash. McMoRan paid preferred dividends of $1.6 million in 2003 and $0.9 million during the second half of 2002. As of December 31, 2003, McMoRan has amortized a total of $0.2 million of its convertible preferred stock issuance costs.

McMoRan used a portion of the proceeds from the offering to repay all remaining borrowings outstanding under its now-terminated sulphur credit facility (Note 5) and used the remaining funds for its working capital requirements and other general corporate purposes.

7. DISCONTINUED OPERATIONS

In November 1998, McMoRan acquired Freeport Sulphur (now Freeport Energy), a business engaged in the purchasing, transporting, terminaling, processing, and marketing of recovered sulphur and the production of oil reserves at Main Pass. Prior to August 31, 2000, Freeport Sulphur was also engaged in mining of sulphur. In June 2002, Freeport Sulphur sold substantially all of its remaining sulphur assets. As discussed in Note 1 - "Basis of Presentation" above, all of McMoRan's sulphur operations and major classes of assets and liabilities are classified as discontinued operations in the accompanying consolidated statements of operations. All of McMoRan sulphur results are included in the accompanying consolidated statements of operations within the caption "Loss from discontinued operations."

The table below provides a summary of the discontinued results of operations for each of the three years ended December 31, 2003 (amounts in thousands).

	Years Ended December 31,		
	2003	2002	2001
Revenues	$ -	$ 30,810	$ 71,483
Production and delivery costs	-	27,484	78,136
Depletion, depreciation and amortization	529	646	15,269
General and administrative expenses	1,223	3,012	5,202
Contractual obligation for certain postretirement health and welfare costs (Note 11)	1,876	1,682	14,381
Operating loss	(3,628)	(2,014)	(41,505)
Interest expense	-	(3,504)	(5,546)
Other income, net	(7,605)[a]	4,265[b]	3,791[c]
Net loss from discontinued sulphur operations	(11,233)	(1,253)	(43,260)
Gain on sale of asset	-	750[d]	-
Total loss from discontinued operations	$ (11,233)	$ (503)	$ (43,260)

a. Includes an estimated $5.9 million loss on the ultimate disposition of the remaining sulphur railcars (Note 12), as well caretaking and insurance costs for the closed sulphur facilities.
b. Includes a $5.0 million gain on completion of the Caminada reclamation activities, a $5.2 million gain associated with adjusting the estimated reclamation cost for Main Pass based on a fixed cost contract with a third party and an aggregate $4.6 million loss on the disposal of the sulphur transportation and terminaling assets.
c. The amount includes a $3.9 million gain associated with the sale of a certain sulphur facilities.
d. Represents proceeds from the sale of an oil and gas asset that was previously written off.

Exit From Sulphur Business
In July 2000, McMoRan undertook a plan to exit its sulphur mining operations conducted at its offshore mining facilities at Main Pass and to sell its sulphur transportation and terminaling assets. The Main Pass sulphur mine ceased production on August 31, 2000.

Sale of Sulphur Transportation and Terminaling Assets. In June 2002, Freeport Sulphur sold substantially all the assets used in its sulphur transportation and terminaling business to Gulf Sulphur Services Ltd., LLP, a joint venture owned equally by IMC Global Inc. (IMC Global) and Savage Industries Inc. In connection with this transaction, McMoRan and IMC Global settled all outstanding disputes between the companies and their respective subsidiaries. In addition, Freeport Sulphur's contract to supply sulphur to IMC Global also terminated upon completion of the transactions. The transactions provided Freeport Sulphur with $58.0 million in gross proceeds, which it used to fund a portion of its remaining sulphur working capital requirements, transaction costs and to repay a substantial portion of its borrowings under the sulphur credit facility (Note 5). At December 31, 2003, approximately $1.0 million of the funds, including accumulated interest income, from these transactions remained deposited in various restricted escrow accounts, which will be used to partially fund Freeport Energy's remaining sulphur-related working capital requirements and to provide funding for certain retained environmental obligations further discussed below. As a result of these transactions, McMoRan's results for 2002 include a $4.6 million loss associated with the disposition of the sulphur transportation and terminaling assets, including the estimated loss on the disposal of certain railcars. During the second half of 2003, McMoRan recorded an aggregate $5.9 million estimated loss on the ultimate disposal of its remaining sulphur railcars (Notes 11 and 12).

The assets sold to Gulf Sulphur Services included Freeport Sulphur's terminal facilities at Galveston, Texas, its terminals at Tampa and Pensacola, Florida, its marine transportation assets and other assets and commercial contracts associated with its sulphur transportation and terminaling business. The $0.3 million of sulphur business assets remaining at December 31, 2003 primarily represents the remaining net book value of the terminal facility at Port Sulphur, Louisiana, which was not transferred to Gulf Sulphur Services and is being marketed separately.

In connection with the preceding transactions, McMoRan also agreed to be responsible for any historical environmental obligations relating to its former sulphur transportation and terminaling assets and also agreed to indemnify Gulf Sulphur Services and IMC Global from any liabilities with respect to the historical sulphur operations engaged in by Freeport Sulphur and its predecessor companies, including reclamation obligations. In addition, McMoRan assumed, and agreed to indemnify IMC Global from, any obligations, including environmental obligations, other than liabilities existing and identified as of the closing of the sale, associated with historical oil and gas operations undertaken by the Freeport-McMoRan companies prior to the 1997 merger of Freeport-McMoRan Inc. and IMC Global. Although potential liabilities for these historical obligations may exist, McMoRan currently believes that it has no liability for them (Note 11).

Main Pass. In June 2001, Freeport Sulphur received $2.5 million in cash from Homestake Sulphur Company LLC (Homestake) and its 16.7 percent interest in the Main Pass oil assets and sulphur mine in return for assuming Homestake's remaining future Main Pass reclamation obligations associated with the related facilities. McMoRan accounted for the transaction as a purchase and began consolidating this acquired interest in Main Pass in its financial statements beginning June 1, 2001. McMoRan recorded no gain or loss on the transaction.

During 2001 Freeport Sulphur pursued discussions with offshore oil and gas producers, gas storage and transportation companies, oil and gas service companies and other energy-related companies about projects involving various alternative commercial uses of the Main Pass sulphur mine facilities. Freeport Sulphur negotiated an agreement with a third party to engage in commercial brine production and to pursue the storage of non-hazardous oil field wastes at Main Pass. Commercial brine production commenced in the first quarter of 2001 and the non-hazardous oil field waste storage operations have previously been submitted for regulatory approval by the Minerals Management Service (MMS). The agreement between McMoRan and the third party has been terminated and McMoRan is now operator of the commercial brine operations.

In December 2002, McMoRan formed a new joint venture that acquired the Main Pass oil producing assets (Note 4).

Sulphur Reclamation Obligations
Prior to 2002, McMoRan completed certain dismantlement and removal (reclamation) activities at the Main Pass sulphur mine, including the plugging and abandonment of the sulphur wells and the removal of the living quarters and warehouse facility. During 2001, McMoRan incurred reclamation costs totaling $9.8 million associated with these reclamation activities. During the first quarter of 2002, McMoRan entered into Turnkey Contracts with Offshore Specialty Fabricators Inc. ("OSFI") to dismantle and remove the remaining Main Pass and Caminada sulphur facilities (see below).

In July 2001, the MMS, which has regulatory authority to ensure offshore leaseholders fulfill the abandonment and site clearance obligations related to their properties, informed McMoRan that they were considering requiring Freeport Sulphur or McMoRan either to post a bond of approximately $35 million or to enter into other funding arrangements acceptable to the MMS, relative to reclamation of the Main Pass sulphur mine and related facilities as well as the Main Pass oil production facilities. In October 2001, Freeport Sulphur entered into a trust agreement with the MMS to provide financial assurances meeting the MMS requirements by February 3, 2002. The MMS has subsequently extended the compliance date for the trust agreement, most recently until February 17, 2004 (Note 12). If requested by McMoRan, K1 USA will provide credit support to cover up to $10 million of MMS bonding requirements covering the Main Pass oil assets now owned by K-Mc I. McMoRan and its subsidiaries' ongoing compliance with applicable MMS requirements will be subject to meeting certain financial and other criteria.

In the first quarter of 2002, Freeport Sulphur and OSFI entered into Turnkey Contracts agreements for the reclamation of the Main Pass and Caminada sulphur mines and related facilities located offshore in the Gulf of Mexico. During the second quarter of 2002, OSFI completed its reclamation activities at the Caminada mine site and McMoRan recorded a $5.0 million gain associated with the resolution of its Caminada sulphur reclamation obligations and the related conveyance of certain assets to OSFI, as further discussed below. In August 2002, OSFI commenced its Phase I reclamation work at Main Pass, which has been substantially completed. McMoRan recorded a $5.2 million gain during 2002 in connection with the reduction in the estimated Main Pass Phase I accrued reclamation costs. The gains from both the Caminada and Phase I reclamation activities are included within the caption "Loss from discontinued operations" in the accompanying consolidated statements of operations and the remaining amount related to the Phase I reclamation obligation is included in current liabilities in the accompanying consolidated balance sheet at December 31, 2003.

As payment of its share of these reclamation costs, Freeport Sulphur conveyed certain assets to OSFI including a supply service boat, its dock facilities in Venice, Louisiana, and certain assets Freeport Sulphur previously salvaged during a prior reclamation phase at Main Pass. When Freeport Sulphur entered into the contractual agreements with OSFI, the parties expected to dispose of the Main Pass oil facilities and related reclamation obligations through a sale of those assets to a specified third party, with payment of the sales proceeds to be remitted to OSFI as it completed the Phase I Main Pass sulphur reclamation activities. In addition, the parties contemplated that a third party would acquire the remaining Main Pass sulphur facilities and establish and operate a new business enterprise. As contemplated, Freeport Sulphur would have received an initial cash payment, which would have been paid to OSFI for its reclamation work, and Freeport Sulphur and OSFI would have shared a retained revenue or profit interest from this new enterprise. Neither the sale transaction nor the formation of the new business enterprise occurred.

In August 2002, Freeport Sulphur and OSFI amended the contract to clarify certain aspects, including specifying values for the reclamation of the Phase I structures at Main Pass. Under the terms of this arrangement, compensation for the Phase I reclamation activities was to be $13 million and OSFI's compensation for reclamation obligations outside of Phase I (Phase II) was the potential share of retained revenue or profit interest described above. Freeport Sulphur had no fixed obligation to pay this $13 million, as it was contingent upon the conclusion of the two specified transactions. Following the failure of the two specified transactions to occur, OSFI informed Freeport Sulphur that it could not perform the reclamation obligations that it had assumed under the Turnkey Contract. Freeport Sulphur and OSFI then reached a further agreement which, in substance, provided that if OSFI received $13 million for Phase I reclamation and was released from its Phase II reclamation obligation, OSFI would have no right to participate in any royalty or net profit interest or any other right relating to the sale of the sulphur lease and Phase II sulphur facilities. OSFI has refused to honor this agreement. In order to fund this $13 million amount, McMoRan entered into the K-Mc I joint venture and conveyed to it the Main Pass oil facilities (Note 4).

As a result of the various changes in the structure of the arrangement with OSFI, the formation of K-Mc I, Freeport Energy's plans for the Main Pass Energy Hub™ project, and OSFI's performance of its Phase I reclamation activities, Freeport Sulphur elected to release OSFI from future services to be rendered associated with the Phase II reclamation requirements and its potential future participation in any use of the remaining Main Pass sulphur facilities. Freeport Sulphur is currently in litigation with OSFI with respect to the rights and obligations of each party under these arrangements (Note 11). In the event that the remaining Main Pass sulphur facilities cannot be used in the future to establish a new business, additional reclamation work covering the remaining sulphur facilities will be required on an accelerated basis.

8. EMPLOYEE BENEFITS

Stock-Based Awards. In May 2003, the McMoRan shareholders approved the McMoRan 2003 Stock Incentive Plan (the 2003 Plan). The 2003 Plan is authorized to grant stock options, stock appreciation rights and restricted stock units (RSUs) (collectively stock-based awards) representing 2,000,000 McMoRan common shares. In May 2001, the McMoRan shareholders approved the McMoRan 2001 Stock Incentive Plan (the 2001 Plan). The 2001 Plan is authorized to grant stock-based awards representing 1,250,000 McMoRan common shares. In May 2000, the McMoRan shareholders approved the McMoRan 2000 stock option plan (the 2000 Plan). The 2000 Plan is authorized to grant stock-based awards representing up to 600,000 McMoRan common shares. In 1998, the MOXY and Freeport Sulphur shareholders approved the McMoRan 1998 Stock Option Plan (the 1998 Plan) in connection with the Merger. The 1998 Plan is authorized to grant stock-based awards representing up to 775,000 McMoRan common shares. McMoRan also adopted the McMoRan 1998 Stock Option Plan for Non-Employee Directors (the Director Plan), authorizing McMoRan to grant non-employee directors stock-based awards to purchase up to 75,000 McMoRan common shares. Generally, under each of these plans, the stock-based awards granted are exercisable in 25 percent annual increments beginning one year from the date of grant and will expire 10 years after the date of grant. Stock based awards representing 1,412,250 McMoRan common shares were available for grant as of December 31, 2003, including stock based awards representing 1,371,000 shares under the 2003 Plan, 4,000 shares under the 2001 Plan, 7,375 shares under the 2000 Plan, 3,375 shares under the 1998 Plan, and 26,500 shares under the Director Plan.

In April 2002 and May 2003, McMoRan's Board of Directors granted RSUs to certain employees that will be converted ratably into 50,000 shares (April 2002) and 100,000 shares (May 2003) of McMoRan common stock on the respective grant anniversary dates over the next three years. In April 2003, McMoRan issued 16,667 shares of its common stock associated with the first anniversary date for the April 2002 RSU grant. All of the remaining RSUs granted were outstanding at December 31, 2003. At December 31, 2003, McMoRan did not have any stock appreciation rights outstanding.

A summary of stock options outstanding follows:

	2003		2002		2001	
	Number of Options	Average Option Price	Number of Options	Average Option Price	Number of Options	Average Option Price
Beginning of year	3,393,211	$14.81	2,448,402	$17.07	1,901,952	$17.42
Granted	766,000	7.71	1,188,250	9.90	648,000	16.06
Exercised	(51,119)	11.92	-	-	(3,724)	13.21
Expired/forfeited	(38,520)	15.69	(243,441)	13.54	(97,826)	17.33
End of year	4,069,572	13.50	3,393,211	14.81	2,448,402	17.07
Exercisable at end of year	2,925,891		2,283,083		1,466,901	

Summary information of all stock options outstanding at December 31, 2003 follows:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Options	Weighted Average Remaining Life	Weighted Average Option Price	Number Of Options	Weighted Average Option Price
$3.88 to $4.28	32,000	8.4 years	$ 3.97	8,000	$ 3.97
$6.17 to $7.52	1,244,250	8.6 years	6.97	429,687	7.11
$10.56 to $15.78	1,165,581	5.9 years	13.41	1,123,456	13.42
$16.28 to $22.14	1,573,041	4.8 years	18.52	1,310,038	18.93
$25.31	54,700	4.3 years	25.31	54,700	25.31
	4,069,572			2,925,881	

In connection with McMoRan's efforts to reduce its administrative and overhead cash expenditures, in early 2002 the Co-Chairmen of McMoRan's Board of Directors agreed to forgo all cash compensation during 2002 in exchange for special stock option grants. In January 2002, a total of 575,000 immediately exercisable stock options were granted, each having a term of ten years and an exercise price of $14.00 per share.

In February 2003, McMoRan's Board of Directors approved the grant of options to purchase 737,500 shares of McMoRan common stock at $7.52 per share, including a total of 525,000 shares granted to its Co-Chairmen from the 2003 Plan. Options on 300,000 of the shares were granted to McMoRan's Co-Chairmen in lieu of cash compensation during 2003 and were immediately exercisable. The remainder, including the options for the remaining 225,000 shares granted to the Co-Chairmen, vest ratably over a four-year period. The 2003 Plan, including grants to the Co-Chairmen, was subject to shareholder approval, which occurred at McMoRan's annual shareholders' meeting on May 1, 2003. Pursuant to accounting requirements, the difference between the market price ($4.99 per share) when the Board approved the grants and the market price on May 1, 2003 ($12.51 per share) is being charged to earnings as the options vest. McMoRan recorded noncash compensation charges totaling $1.8 million during 2003 related to these grants, including a $1.5 million charge for the immediately exercisable options during the second quarter of 2003. During 2003, McMoRan recorded approximately $0.8 million of the total compensation expense associated with its stock-based awards, including its RSU compensation expense (Note 1) as general and administrative expense, with the remainder being classified as exploration expense.

Pension Plans and Other Benefits.
During 2000, McMoRan elected to terminate its defined benefit pension plan covering substantially all its employees and replace this plan with a defined contribution plan, as further discussed below. All participants' account balances in the defined benefit plan were fully vested on June 30, 2000. The plans' investment portfolio was liquidated and invested primarily in short duration fixed-income securities in the fourth quarter of 2000 to reduce exposure to equity market volatility. Interest credits will continue to accrue under the plan until the assets are liquidated, which will occur once approval is obtained from the Internal Revenue Service and the Pension Benefit Guaranty Corporation. Upon receiving this approval, McMoRan will make the final distribution of the participants' account balances, which will require McMoRan to fund any shortfall between these obligations and the plan assets. At December 31, 2003, the plan's assets had a fair value of $8.9 million and the shortfall approximated $1.6 million. McMoRan will also have to fund a portion of the pension obligations associated with FM Services' employees (Notes 4 and 10), which at December 31, 2003 approximated $0.5 million.

McMoRan also provides certain health care and life insurance benefits (Other Benefits) to retired employees. McMoRan has the right to modify or terminate these benefits. McMoRan recognized a curtailment loss of $0.4 million in 2002 resulting from its terminating substantially all of its remaining sulphur employees, following the sale of the assets comprising its recovered sulphur business (Note 7). McMoRan also recorded approximately $0.2 million in special termination benefits associated with certain of these employees. The initial health care cost trend rate used for the Other Benefits was 11 percent in 2004, decreasing ratably annually until reaching 5.0 percent in 2009. A one-percentage-point increase or decrease in assumed health care cost trend rates would not have a significant impact on service or interest costs. Information on the McMoRan plans follows (dollars in thousands):

	Pension Benefits		Other Benefits	
	2003	2002	2003	2002
Change in benefit obligation:				
Benefit obligation at the beginning of year	$ (11,499)	$ (11,543)	$ (7,850)	$ (5,981)
Service cost	-	-	(26)	(37)
Interest cost	(413)	(581)	(434)	(505)
Change in Plan payout assumptions	426	-	-	-
Curtailment loss	-	-	-	(397)
Special termination benefits	-	-	-	(164)
Actuarial gains (losses)	-	-	632	(1,361)
Participant contributions	-	-	(196)	(205)
Benefits paid	928	625	696	800
Benefit obligation at end of year	(10,558)	(11,499)	(7,178)	(7,850)
Change in plan assets:				
Fair value of plan assets at beginning of year	9,535	9,658	-	-
Return on plan assets	334	502	-	-
Employer/participant contributions	-	-	696	800
Benefits paid	(928)	(625)	(696)	(800)
Fair value of plan assets at end of year	8,941	9,535	-	-
Funded status	(1,617)	(1,964)	(7,178)	(7,850)
Unrecognized net actuarial gain	-	-	2,500	3,278
Unrecognized prior service cost	-	-	4	5
Accrued benefit cost	$ (1,617)	$ (1,964)	$ (4,674)	$ (4,567)
Weighted-average assumptions (percent):				
Discount rate	N/A[a]	N/A	6.25	6.75
Expected return on plan assets	N/A	N/A	-	-
Rate of compensation increase	N/A	N/A	-	-

a. As discussed above, McMoRan elected to terminate its defined benefit pension plan on June 30, 2000.

Expected benefit cost for McMoRan's other benefits plan total $0.5 million in 2004, $0.6 million in 2005, $0.7 million in 2006, $0.8 million in 2007 and 2008 and a total of $3.6 million during 2009 through 2013. The components of net periodic benefit cost for McMoRan's plans follow (in thousands):

	Pension Benefits			Other Benefits		
	2003	2002	2001	2003	2002	2001
Service cost	$ -	$ -	$ -	$ 26	$ 37	$ 62
Interest cost	413	581	433	434	505	335
Curtailment loss	-	-	-	-	397	-
Special termination benefits	-	-	-	-	164	-
Return on plan assets	(334)	(502)	(286)	-	-	-
Amortization of prior service costs	-	-	-	1	1	1
Recognition of net actuarial loss	-	-	-	154	177	7
Net periodic benefit cost	$ 79	$ 79	$ 147	$ 615	$ 1,281	$ 405

McMoRan has an employee savings plan under Section 401(k) of the Internal Revenue Code. The plan allows eligible employees to contribute up to 50 percent of their pre-tax compensation, subject to a limit prescribed by the Internal Revenue Code, which was $12,000 for 2003, $11,000 for 2002 and $10,500 for 2001. McMoRan matches 100 percent of each employees' contribution up to a maximum of 5 percent of the each employees' annual basic compensation amount. As a result of McMoRan's decision to terminate its defined benefit pension plan effective July 1, 2000, McMoRan fully vested all active Section 401(k) savings plan participants on June 30, 2000.

Subsequently, all new plan participants will vest in McMoRan's matching contributions upon three years of service with McMoRan. Additionally, McMoRan established a defined contribution plan for substantially all its employees. Under this plan, McMoRan contributes amounts to individual employee accounts totaling either 4 percent or 10 percent of each employee's pay, depending on a combination of each employee's age and years of service with McMoRan. McMoRan charged $0.2 million in 2003, $0.4 million in 2002 and $0.6 million in 2001 to its results of operations for the Section 401(k) savings plan and the defined contribution plan. Additionally, McMoRan has other employee benefit plans, certain of which are related to McMoRan's performance, which costs are recognized currently in general and administrative expense.

McMoRan also has a contractual obligation to reimburse IMC Global for a portion of their postretirement benefit costs relating to certain former retired sulphur employees (Note 11).

9. INCOME TAXES

McMoRan accounts for income taxes pursuant to SFAS 109, "Accounting for Income Taxes." McMoRan has a net deferred tax asset of $187.5 million as of December 31, 2003, resulting from net operating loss carryfowards and other temporary differences related to McMoRan's activities. McMoRan has provided a valuation allowance, including approximately $29 million associated with McMoRan's sulphur operations, for the full amount of these net deferred tax assets. The components of McMoRan's net deferred tax asset at December 31, 2003 and 2002 follow (in thousands):

	December 31, 2003	December 31, 2002
Net operating loss carryforwards (expire 2006-2023)	$ 133,719	$ 121,601
Property, plant and equipment	27,203	22,518
Reclamation and shutdown reserves	7,417	16,289
Deferred compensation, postretirement and pension benefits and accrued liabilities	10,845	10,672
Other	8,302	5,528
Less valuation allowance	(187,486)	(176,608)
Net deferred tax asset	$ -	$ -

McMoRan's income tax provision consisted entirely of state income taxes, which totaled $1,000 in 2003, $7,000 in 2002 and $8,000 in 2001.

Reconciliations of the differences between income taxes computed at the federal statutory tax rate and the income taxes recorded follow (dollars in thousands):

	2003		2002		2001	
	Amount	Percent	Amount	Percent	Amount	Percent
Income tax (expense) benefit computed at the federal statutory income tax rate	$ 10,821	35%	$ (6,314)	35%	$ 51,821	35%
Change in valuation allowance	(10,878)	(35)	11,201	(62)	(48,551)	(33)
State taxes and other	56	-	(4,894)	27	(3,278)	(2)
Income tax provision	$ (1)	- %	$ (7)	- %	$ (8)	-%

10. TRANSACTIONS WITH AFFILIATES

Effective October 1, 2002, McMoRan sold its 50 percent equity investment in FM Services Company (FM Services) for $1.3 million, realizing a gain of $1.1 million. This gain is reflected within "Other Income" in the accompanying consolidated statements of operations. FM Services continues to provide McMoRan with certain administrative, financial and other services on a contractual basis. These service costs, which include related overhead, totaled $3.3 million in 2003, $2.2 million in 2002 and $10.6 million in 2001. Management believes these costs do not differ materially from the costs that would have been incurred had the relevant personnel providing the services been employed directly by McMoRan. The reduced costs paid to FM Services since 2001 reflect the corresponding reduction in services provided to McMoRan following certain substantial sales transactions (Notes 2 and 4), as well as the effect of the Co-Chairmen of McMoRan's Board of Directors agreeing not to receive any cash compensation during both 2003 and 2002 (Note 8). At December 31, 2003, McMoRan had an obligation to fund $3.2 million of FM

Services benefit costs, primarily reflecting employee pension and postretirement medical obligations (Notes 4 and 8).

11. COMMITMENTS AND CONTINGENCIES

Commitments. Effective January 1, 2000, McMoRan entered into an agreement with Texaco that committed it to expend $110 million by June 30, 2003 for exploration of the prospects that Texaco made available to McMoRan (Note 2). McMoRan met this commitment by expending or having others expend a total of $112.0 million under the terms of the agreement through December 31, 2002.

McMoRan has entered into a new multi-year exploration arrangement and plans to drill between 10 to 12 wells during the next twelve months (Note 12). At December 31, 2003, McMoRan had no commitments related to its planned drilling activities for 2004.

Previously, McMoRan had a contract with CLK Company LLC (CLK), an independently owned company, to provide geological and geophysical evaluation services to McMoRan on an exclusive basis. The contract formerly provided for an annual retainer fee of $2.5 million ($0.5 million of the annual fee was paid for in McMoRan common stock, recorded at fair market value at the time issued), plus certain expenses and a three percent overriding royalty interest in prospects accepted by McMoRan. Effective January 1, 2002, the contract with CLK was amended to reduce the cost of the annual retainer fee to $2.0 million, with $0.9 million of the 2002 fee paid in McMoRan common stock. The CLK contract was terminated on December 31, 2002 and was replaced with a short-term transition agreement, effective January 1, 2003, eliminating the annual retainer. Costs of services provided by CLK totaled less than $0.1 million in 2003, $2.2 million in 2002 and $3.4 million in 2001. In connection with the most recent amendment of the CLK contract, McMoRan has been assigned the remaining portion of CLK's office lease in Houston Texas (see below).

Long-term Contracts and Operating Leases. As discussed in Note 7, in 2002 McMoRan sold its sulphur transportation and terminaling assets to a sulphur services joint venture, which assumed the substantial majority of its non-cancelable long-term contracts and operating leases. Substantially all of McMoRan's remaining operating leases at December 31, 2003 involved the leasing of sulphur railcars previously used in its recovered sulphur business and certain office space (see "Commitments" above). In January 2004, McMoRan terminated its sulphur railcar lease, which was originally scheduled to expire in March 2011, and sold the railcars to a third party (Note 12). During 2003, McMoRan recorded an aggregate $5.9 million estimated loss on the ultimate disposal of the remaining sulphur railcars. The loss is included within the caption "Loss from discontinued operations" in the accompanying consolidated statements of operations. Excluding the recently terminated railcar lease amounts, McMoRan's total minimum annual contractual charges aggregate $0.6 million, $0.3 million in 2004, $0.2 million in 2005 and $0.1 million in 2006.

McMoRan had a sublease arrangement with IMC Global for all the railcars under lease through 2003. The sublease agreement expired on December 31, 2003 and continues thereafter on a month-to-month basis. While the sublease is in effect, McMoRan receives a sufficient amount of sublease income to offset its railcar costs.

Other Liabilities. Freeport Sulphur has an contractual obligation to IMC Global to reimburse for a portion of IMC Global's postretirement benefit costs relating to certain retired employees of Freeport Sulphur. As a result of a significant increase in costs incurred under this obligation during the fourth quarter of 2001, McMoRan had its external benefit consultant update the estimated related future costs using an initial health care cost trend rate of 11 percent decreasing ratably to 5 percent over a six-year period and a discount rate of 7.5 percent. Accordingly, McMoRan accrued $13.6 million at December 31, 2001 to increase the recorded liability. During 2003, McMoRan again had its external benefit consultants update the estimate of the related costs associated with this contractual obligation to assess the impact of certain changes made to the underlying benefit plans of IMC Global and current estimated health care cost trends. In their analysis, the external benefit consultant used an initial health care cost trend rate of 12 percent decreasing ratably to 5 percent in 2010 and a discount rate of 7.5 percent. This contractual obligation totaled $23.6 million at December 31, 2003, including $1.6 million in current liabilities from discontinued operations. At December 31, 2002, this contractual obligation totaled $23.0 million, including $1.4 million in current liabilities from discontinued operations. Future changes to this estimate resulting from changes in assumptions or actual results varying from projected results will be recorded in earnings.

During 2000, Freeport Sulphur negotiated a termination of a sulphur-related obligation assumed in a previous purchase of certain sulphur transportation and terminaling assets by paying $6.0 million and placing $3.5 million in an escrow account to fund certain assumed environmental liabilities associated with the acquired sulphur assets. The restricted escrowed funds, which approximate McMoRan's estimate of the assumed environmental liabilities, is classified as a long-term asset and recorded in "Restricted investments and cash" in the accompanying consolidated balance sheets.

Environmental and Reclamation. McMoRan has made, and will continue to make, expenditures for the protection of the environment. McMoRan is subject to contingencies as a result of environmental laws and regulations. Present and future environmental laws and regulations applicable to McMoRan's operations could require substantial capital expenditures or could adversely affect its operations in other ways that cannot be predicted at this time. See Note 4 for further information about McMoRan's efforts to resolve its sulphur reclamation obligations with the MMS and its assuming potential obligations in connection with the sale of its sulphur transportation and terminaling assets. As of December 31, 2003, McMoRan has not recorded any amounts associated with its agreement to assume certain historical oil and gas liabilities from IMC Global because no specific liability has been identified that is reasonably probable of requiring McMoRan to fund any future material amounts.

Effective January 1, 2003, McMoRan adopted SFAS No. 143 (Note 1). At December 31, 2003, McMoRan revised its reclamation and well abandonment estimates for (1) changes in the projected timing of certain reclamation costs because of changes in reserve estimates and (2) changes in its credit-adjusted risk free interest rate which ranged from 4.8 percent to 10.0 percent. At December 31, 2003, McMoRan estimates these undiscounted obligations to be approximately $35.9 million, including $26.7 million associated with its remaining sulphur obligations. At December 31, 2003, McMoRan's estimated discounted asset retirement obligations totaled $21.3 million, including $14.0 million associated with its remaining sulphur obligations. A rollforward of McMoRan's consolidated discounted asset retirement obligations follows (in thousands):

	Oil and Gas	Sulphur
Asset retirement obligations at beginning of year:	$ 7,899	$ 19,136
Liabilities settled	(699)	(5,664)
Accretion expense	470	826
Revision for changes in estimates	(397)	(297)
Asset retirement obligation at end of year	$ 7,273	$ 14,001

Litigation. McMoRan is currently involved in litigation regarding the reclamation of its remaining Main Pass sulphur facilities. This litigation includes Freeport Sulphur's dispute with OSFI, regarding each parties' rights and obligations under a Turnkey contract dated March 28, 2002. As further discussed in Note 7, "Discontinued Operations - Sulphur Reclamation Obligations," under the terms of the Turnkey Contract Freeport Sulphur had no fixed obligation to pay $13 million to OSFI as compensation for the Phase I reclamation activities, as any such payment was contingent upon the conclusion of two specified transactions. Following the failure of the two specified transactions to occur, OSFI informed Freeport Sulphur that it could not perform the reclamation obligations that it had assumed under the Turnkey Contract. Freeport Sulphur and OSFI then reached a further agreement which, in substance, provided that if OSFI received $13 million for Phase I reclamation and was released from its Phase II reclamation obligation, OSFI would have no right to participate in any royalty or net profit interest or any other right relating to the sale of the sulphur lease and Phase II sulphur facilities. OSFI has refused to honor this agreement. In the lawsuit, Freeport Sulphur alleges that OSFI failed to timely complete the Phase I reclamation under the Turnkey Contract. OSFI has counterclaimed against Freeport Sulphur for alleged breaches of the Turnkey Contract, claiming that it did in fact timely complete the Phase I reclamation and seeks recovery of $2.6 million plus contractual interest, attorney's fees and expenses, and confirmation of an equal share in any profitable use of the Phase II facilities. A trial date is set for May 2004.

McMoRan may from time to time be involved in various legal proceedings of a character normally incident to the ordinary course of its business. Management believes that potential liability from any of these pending or threatened proceedings will not have a material adverse effect on McMoRan's financial condition or results of operations.

NOTE 12. SUBSEQUENT EVENTS

In January 2004, McMoRan announced the formation of a multi-year exploration joint venture with a private exploration and production company. Under terms of the agreement, the private company has committed to fund a minimum of $200 million for its share of the joint venture's exploration costs and will participate for 40 percent of McMoRan's interest in prospects, located outside the JB Mountain and Mound Point areas. The joint venture plans to drill 10 to 12 wells over the next twelve months, with one well (the Dawson Deep prospect at Garden Banks 625) now drilling and three expected to commence in the first quarter of 2004. McMoRan has agreed to propose and drill an initial test well at 11 prospects by December 31, 2005 or refund the private company's investment in the Dawson Deep prospect. As of December 31, 2003 the private company's investment in the Dawson Deep prospect totaled $2.1 million.

On January 14, 2004, McMoRan entered into a definitive sales agreement for its remaining sulphur railcars. Under the terms of the agreement, McMoRan will receive $1.0 million for all of its railcars and an additional $0.1 million if it makes delivery of all the cars by April 30, 2004. On January 15, 2004 in conjunction with this sales agreement, McMoRan terminated its existing lease agreement for the remaining sulphur railcars by paying $7.0 million to the lessor for the remaining commitments under the lease (of which $5.9 million was expensed in 2003).

On February 16, 2004, McMoRan proposed that the trust agreement between Freeport Energy and the MMS be terminated and replaced with financial assurances from MOXY (Note 7).

On February 27, 2004, pursuant with the requirements of the U.S. Deepwater Port Act, Freeport Energy filed an application with U.S. Coast Guard requesting a license that will authorize Freeport Energy to receive and process LNG and store and distribute natural gas at the Main Pass Energy Hub™ (Note 3).

13. SUPPLEMENTARY OIL AND GAS INFORMATION

McMoRan's oil and gas exploration, development and production activities are conducted in the offshore Gulf of Mexico and onshore Gulf Coast areas of the United States. Supplementary information presented below is prepared in accordance with requirements prescribed by SFAS 69 *"Disclosures about Oil and Gas Producing Activities."*

Oil and Gas Capitalized Costs.

	Years Ended December 31,	
	2003	2002
	(In Thousands)	
Unevaluated properties [a]	$ 5,976	$ 9,239
Evaluated	183,530	175,461
Subtotal	189,506	184,700
Less accumulated depreciation and amortization	(163,371)	(146,805)
Net oil and gas properties	$ 26,135	$ 37,895

a. Includes costs associated with wells in progress totaling $2.1 million at December 31, 2003. There were no costs associated with wells in progress at December 31, 2002.

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities.

	Years Ended December 31,		
	2003	2002	2001
	(In Thousands)		
Acquisition of properties:			
Proved	$ -	$ -	$ 4,322
Unproved	-	-	859
Exploration costs	11,356	7,642	35,475
Development costs	7,558	3,788	45,983
	$ 18,914	$ 11,430	$ 86,639

Proved Oil and Gas Reserves (Unaudited). Proved oil and gas reserves at December 31, 2003 have been estimated by Ryder Scott Company, L.P., an independent petroleum engineering firm, in accordance with guidelines established by the Securities and Exchange Commission (SEC), which require such estimates to be based upon existing economic and operating conditions as of year-end without consideration of expected changes in prices and costs or other future events. All estimates of oil and gas reserves are inherently imprecise and subject to change as new technical information about the properties is obtained. Estimates of proved reserves for wells with little or no production history are less reliable than those based on a long production history. Subsequent evaluation of the same reserves may result in variations which may be substantial. Additionally, SEC regulations require the use of certain restrictive definitions based on a concept of "reasonable certainty" in the determination of proved oil and gas reserves and related cash flows. Substantially all of McMoRan's proved reserves are located offshore in the Gulf of Mexico. Oil, including condensate and plant products, is stated in thousands of barrels and natural gas in millions of cubic feet (MMcf).

	Oil			Gas		
	2003	2002	2001	2003	2002	2001
Proved reserves:						
Beginning of year	579	6,373	5,507	13,983	48,317	56,842
Revisions of previous estimates	92	(19)	1,360	1,595	(2,060)	(4,406)
Discoveries and extensions	-	-	54	-	-	7,018
Production	(124)	(1,153)	(1,417)	(2,011)	(5,851)	(11,137)
Sale of reserves	-	(4,622)	-	-	(26,423)	-
Purchase of reserves	-	-	869	-	-	-
End of year	547[a]	579	6,373	13,567[a]	13,983	48,317
Proved developed reserves:						
Beginning of year	412	6,099	4,843	8,222	35,872	35,584
End of year	389	412	6,099	8,074	8,822	35,872
Equity in proved reserves of unconsolidated affiliate[b]	1,561	1,939	-	-	-	-

a. In January 2004, McMoRan announced the formation of a multi-year joint venture (Note 12). Pursuant to this arrangement, planned drilling arrangements would reduce McMoRan's reserves by approximately 36,000 barrels of oil and 1.1 Bcf of natural gas, and its standardized measure by approximately $6.2 million.
b. Represents McMoRan's 33.3 percent equity interest in K-Mc I, which owns the oil operations at Main Pass. McMoRan's ability to realize the cash flows associated with these reserves is subordinated to repaying the debt of K-Mc I and establishing a sinking fund for the Main Pass oil reclamation obligations (Note 2).

Standardized Measure of Discounted Future Net Cash Flows From Proved Oil and Gas Reserves (Unaudited).
McMoRan's standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves were computed using reserve valuations based on regulations and parameters prescribed by the SEC. These regulations require the use of year-end oil and gas prices in the projection of future net cash flows. The weighted average of these prices for all properties with proved reserves was $32.49 per barrel of oil and $6.28 per Mcf of gas. McMoRan has sufficient tax deductions and operating loss-carryforwards to offset estimated future income taxes.

	December 31,	
	2003	2002
	(In Thousands)	
Future cash inflows	$ 104,787	$ 89,663
Future costs applicable to future cash flows:		
Production costs	(23,061)	(23,356)
Development and abandonment costs	(16,742)	(15,747)
Future net cash flows before income taxes	64,984	50,560
Future income taxes	-	-
Future net cash flows	64,984	50,560
Discount for estimated timing of net cash flows (10% discount rate)	(12,282)	(10,073)
	$ 52,702	$ 40,487
Equity in unconsolidated affiliates' discounted future net cash flows[a]	$ 5,063	$ 7,371

a. Represents McMoRan's 33.3 percent equity interest in K-Mc I, which owns the oil operations at Main Pass. McMoRan's ability to realize the cash flows associated with these reserves is subordinated to repaying the debt of K-Mc I and establishing a sinking fund for the Main Pass oil reclamation obligations (Note 2).

Changes in Standardized Measure of Discounted Future Net Cash Flows From Proved Oil and Gas Reserves (Unaudited).

	Years Ended December 31,		
	2003	2002	2001
	(In Thousands)		
Beginning of year	$ 40,487	$ 68,634	$ 368,991
Revisions:			
Changes in prices	19,174	26,925	(343,526)
Accretion of discount	4,049	6,863	42,947
Change in reserve quantities	7,310[a]	(5,735)	(54,209)
Other changes, including revised estimates of development costs and rates of production	(12,005)	(9,066)	(11,114)
Discoveries and extensions, less related costs	-	-	13,146
Development costs incurred during the year	2,685	3,512	28,231
Change in future income taxes	-	-	60,477
Revenues, less production costs	(8,998)	(17,545)	(37,926)
Sale of reserves in place	-	(33,101)	-
Purchase of reserves in place	-	-	1,617
End of year	$ 52,702	$ 40,487	$ 68,634

a. Includes $9.3 million related to McMoRan's reversionary interests in properties it sold in February 2002 (Note 4).

14. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	Revenues	Operating Income (Loss)	Net Income (Loss)[a]	Net Income (Loss) per Share Basic	Net Income (Loss) per Share Diluted
	(In Thousands, Except Per Share Amounts)				
2003					
1st Quarter	$ 4,764	$ (2,275)	$ 18,432[b]	$ 1.13	$ 1.13
2nd Quarter	2,703	(9,382)[c]	(11,252)	(0.68)	(0.68)
3rd Quarter	3,850	(10,492)[d]	(19,339)[e]	(1.16)	(1.16)
4th Quarter	4,797	(16,798)[f]	(20,497)	(1.22)	(1.22)
	$ 16,114	$ (38,947)	$ (32,656)	(1.97)	(1.97)
2002					
1st Quarter	$ 13,586	$ 24,536[g]	$ 24,039	$ 1.51	$ 1.51
2nd Quarter	11,400	(1,163)	(2,522)[h]	(0.16)	(0.16)
3rd Quarter	9,785	(12,573)	(10,256)[i]	(0.64)	(0.64)
4th Quarter	8,997	7,142[j]	5,780	0.36	0.27
	$ 43,768	$ 17,942	$ 17,041	1.06	0.91

a. Reflects net income (loss) attributable to common stock, which includes preferred dividends and amortization of convertible preferred stock issuance costs as a reduction to net income.
b. Includes the $22.2 million cumulative effect of change in accounting principle associated with the adoption of SFAS 143 (Note 1).
c. Included a $4.0 million charge to write off the remaining Hornung prospect leasehold costs following the expiration of two of the four leases comprising the prospect (Note 1).
d. Includes the initial $7.1 million of start-up costs associated with the Main Pass Energy Hub™ Project, including $6.2 million associated with the issuance of stock warrants representing 0.76 million McMoRan common shares in September 2003 (Note 2).
e. Includes a $5.7 million charge for the estimate loss on the ultimate disposal of the sulphur railcars. An additional $0.2 million estimated loss was recorded in the fourth quarter of 2003.
f. Includes a $3.9 million impairment charge for the Vermilion Block 160 field, $3.2 million of unproductive exploratory drilling costs and $4.3 million of Main Pass Energy Hub™ Project start-up costs.
g. Includes $29.2 million gain on the sale of three oil and gas properties in February 2002 (Note 4).

h. Includes $5.0 million gain associated with completion of sulphur reclamation activities at the Caminada mine, offset in part by the loss on the disposal of the sulphur transportation and terminaling assets (Note 7).
i. Includes a $5.2 million gain resulting from reducing the Main Pass Phase I accrued reclamation costs from $18.2 million to $13.0 million based upon OSFI fixed cost contract (Note 7).
j. Includes $14.1 million gain from the sale of the oil producing assets at Main Pass to the K-Mc I Joint Venture (Note 4). The gain was partially offset by a $4.4 million impairment charge (Note 1).

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

Arthur Andersen LLP audited our financial statements for 2001 and had served as the company's (and its predecessors') independent auditors since 1994. On July 10, 2002, we decided to replace Arthur Andersen as our independent accountants. This action was taken with the approval of our board of directors, which approved the decision reached by its audit committee. Arthur Andersen ceased to practice before the SEC effective August 31, 2002.

The audit reports issued by Arthur Andersen on our consolidated financial statements as of and for the year ended December 31, 2001, did not contain an adverse opinion or disclaimer of opinion, nor were either qualified or modified as to audit scope or accounting principle; however, the audit opinion for the year ended December 31, 2001 was modified as to an uncertainty concerning our ability to continue as a "going concern."

During the fiscal year that ended December 31, 2001 and continuing through July 10, 2002, we had no disagreements with Arthur Andersen on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, that, if not resolved to Arthur Andersen's satisfaction, would have caused them to make reference to the matter of disagreement in their report on the financial statements. Arthur Andersen has communicated to us that they have informed the SEC that they are unable to provide letters that corroborate or invalidate the statements we have made in this disclosure, as required by the SEC.

None of the reportable events described under Item 304(a)(1)(v) of Regulation S-K occurred during our two most recent fiscal years and through July 10, 2002.

Also on July 10, 2002, we appointed Ernst & Young LLP to replace Arthur Andersen as our independent accountants. Our board also approved its audit committee's selection of Ernst & Young. In February 2003, our audit committee appointed Ernst & Young as our independent accountants for 2003. During the fiscal year ended December 31, 2001, and the subsequent interim period through July 10, 2002, we did not consult with Ernst & Young regarding any of the matters or events set forth in Item 304(a)(2)(i) and (ii) of Regulation S-K.

Item 9A. Controls and Procedures

(a) Evaluation of disclosure controls and procedures. Our chief executive officer and chief financial officer, with the participation of management, have evaluated the effectiveness of our "disclosure controls and procedures" (as defined in Rules 13a-14(c) and 15d-14(c) under the Securities Exchange Act of 1934) as of a date within 90 days prior to filing this annual report on Form 10-K. Based on their evaluation, they have concluded that our disclosure controls and procedures are effective in timely alerting them to material information relating to McMoRan (including our consolidated subsidiaries) required to be disclosed in our periodic SEC filings.

(b) Changes in internal controls. There were no significant changes in our internal controls or in other factors that could significantly affect these controls subsequent to the date of their evaluation.

PART III

Item 10. Directors and Executive Officers of the Registrant

The information set forth under the caption "Information About Nominees and Directors" of the Proxy Statement submitted to the stockholders of the registrant in connection with its 2004 Annual Meeting to be held on May 6, 2004 is incorporated by reference. The information required by Item 10 regarding our executive officers appears in a separately captioned heading after Item 4. in Part II of this report on Form 10-K.

Item 11. Executive Compensation

The information set forth under the captions "Director Compensation" and "Executive Officer Compensation" of the Proxy Statement submitted to the stockholders of the registrant in connection with its 2004 Annual Meeting to be held on May 6, 2004 is incorporated by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management

The information set forth under the captions "Common Stock Ownership of Certain Beneficial Owners" and "Common Stock Ownership of Directors and Executive Officers" of the Proxy Statement submitted to the stockholders of the registrant in connection with its 2004 Annual Meeting to be held on May 6, 2004 is incorporated by reference.

Equity Compensation Plan Information

The following table presents information as of December 31, 2003, regarding equity compensation plans of McMoRan under which common stock may be issued to employees and non employees as compensation.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	4,202,905(1)	$13.50 (1)	1,412,250(2)
Equity compensation plans not approved by security holders	-	-	-
Total	4,202,905(1)	$13.50 (1)	1,412,250(2)

(1) The number of securities to be issued upon the exercise of outstanding options, warrants and rights includes 133,333 nonvested restricted stock units. These grants are not reflected in column (b) as they are not subject to an exercise price.

(2) As of December 31, 2003, there were 3,375 shares remaining available for future issuance under the 1998 Stock Option Plan. All of these shares could be issued under the terms of the plan (a) upon the exercise of options, stock appreciation rights and limited rights, or (b) in the form of "other stock-based" awards, which awards are valued in whole or in part on the value o the shares of common stock. In addition, there were 7,375 shares and 4,000 shares remaining available for future issuance under the 2000 Stock Incentive Plan and the 2001 Stock Incentive Plan, respectively, all of which could be issued under the respective terms of the plans (a) upon the exercise of options, stock appreciation rights and limited rights, or (b) in the form of restricted stock or "other stock-based" awards. There were also 1,371,000 shares remaining available for future issuance under the 2003 Stock Incentive Plan, (i) all of which could be issued under the terms of the plan upon the exercise of options, stock appreciation rights, limited rights and (ii) 400,000 of which could be issued under the terms of the plan in the form of restricted stock or "other-stock based awards."

Item 13. Certain Relationships and Related Transactions

The information set forth under the captions "Certain Transactions" of the Proxy Statement submitted to the stockholders of the registrant in connection with its 2004 Annual Meeting to be held on May 6, 2004 is incorporated by reference.

Item 14. Principal Accountant Fees and Services

The information set forth under the caption "Independent Auditors" of the definitive Proxy Statement to be filed with the Commission, relating to our 2004 Annual meeting to be held on May 6, 2004, is incorporated herein by reference.

PART IV

Item 15. Exhibits, Financial Statement Schedules, and Reports on Form 8-K

(a)(1). Financial Statements. Reference is made to Item 8 hereof.

(a)(2). Financial Statement Schedules. Following is Schedule II - Valuation and Qualifying Accounts and the related Report of Independent Public Auditors. All other financial statement schedules are not required under the related instructions or are inapplicable and therefore have been omitted.

(a)(3). Exhibits. Reference is made to the Exhibit Index beginning on page E-1 hereof.

(b). Reports on Form 8-K. During the last quarter covered by this report the registrant filed two Current Reports on Form 8-K. The registrant filed one Current Report on Form 8-K reporting an event under Item 5. dated October 27, 2003 (filed October 28, 2003) and one Current Report on Form 8-K furnishing information under Item 12 dated October 22, 2003 (filed October 22, 2003).

Subsequent to the end of the year for which this report is filed and prior to the date of its filing, McMoRan filed three Current Reports on Form 8-K. McMoRan filed five Current Reports on Form 8-k reporting events under Item 5 dated January 7, 2004 (filed January 8, 2004),January 16, 2004 (filed January 16, 2004), February 3, 2004 (filed February 4, 2004), February 6, 2004 (filed February 6, 2004) and March 1, 2004 (filed March 2, 2004) and one Current Report on Form 8-K furnishing information under Item 12 dated January 22, 2004 (filed January 23, 2004).

REPORT OF INDEPENDENT AUDITORS

TO THE STOCKHOLDERS AND BOARD OF DIRECTORS
OF McMoRan EXPLORATION CO.:

We have audited the consolidated financial statements of McMoRan Exploration Co. as of December 31, 2003 and 2002 and for each of the two years in the period ended December 31, 2003, and have issued our report thereon dated February 2, 2004. Our audits also included the accompanying schedule of valuation and qualifying accounts (financial statement schedule) for the years ended December 31, 2003 and 2002. This schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. The Company's consolidated financial statements and related schedule of valuation and qualifying accounts for the year ended December 31, 2001 were audited by other auditors who have ceased operations and whose report with respect to the schedule dated April 16, 2002 indicated that such schedule for 2001 fairly states, in all material respects, the financial data required to be set forth therein in relation to the Company's basic consolidated financial statements taken as a whole.

In our opinion, the financial statement schedule for 2003 and 2002 referred to above, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ Ernst & Young LLP

New Orleans, Louisiana
February 2, 2004

This is a copy of the audit report previously issued by Arthur Andersen LLP in connection with McMoRan Exploration Co.'s filing on Form 10-K reporting its results for the year ending December 31, 2001. Arthur Andersen LLP has not reissued this audit report in connection with this filing on Form 10-K for the year ending December 31, 2003.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

TO THE STOCKHOLDERS AND BOARD OF DIRECTORS
OF McMoRan EXPLORATION CO.:

We have audited, in accordance with auditing standards generally accepted in the United States, the financial statements as of December 31, 2001 and 2000 and for each of the three years in the period ended December 31, 2001 included in McMoRan Exploration Co.'s annual report to shareholders included elsewhere in this Form 10-K and have issued our report thereon dated April 15, 2002, which report included a reference to certain matters which raise substantial doubt about the Company's ability to continue as a going concern. Our audits were made for the purpose of forming an opinion on those statements taken as a whole. The schedule that follows is the responsibility of the Company's management and is presented for purposes of complying with the Securities and Exchange Commission's rules and is not part of the basic financial statements. This schedule has been subjected to the auditing procedures applied in the audits of the basic financial statements and, in our opinion, fairly states in all material respects the financial data required to be set forth therein in relation to the basic financial statements taken as a whole.

/s/ Arthur Andersen LLP

New Orleans, Louisiana
April 16, 2002

Schedule II - Valuation and Qualifying Accounts

	Balance at Beginning of Period	Additions: Charged to Costs and Expense	Additions: Charged to Other Accounts	Other - Add (Deduct)	Balance at End of Period
			(In Thousands)		
Reclamation and mine shutdown reserves:					
2003					
Sulphur [a]	$ 38,547	$ 826	$ -	$ (25,372)	$ 14,001
Oil [b]	7,994	470	-	(1,191)[b]	7,273
	$ 46,541	$ 1,296	$ -	$ (26,563)	$ 21,274
2002					
Sulphur	$ 63,876	$ -	$ -	$ (25,329)[c]	$ 38,547
Oil	18,676	668	-	(11,350)[d]	7,994
	$ 82,552	$ 668	$ -	$ (36,679)	$ 46,541
2001					
Sulphur	$ 69,187	$ -	$ -	$ (5,311)[e]	$ 63,876
Oil [d]	15,980	3,466	-	(770)	18,676
	$ 85,167	$ 3,466	$ -	$ (6,081)	$ 82,552

a. McMoRan adopted Statement of Financial Accounting Standards No. 143 "*Accounting for Asset Retirement Obligations*" (SFAS 143) effective January 1, 2003. Amounts include $0.8 million of accretion charges, a $19.4 million reduction of the liabilities upon adoption of SFAS 143, $5.7 million of cost incurred on Phase I Main Pass reclamation activities and a $0.3 million reduction in the SFAS 143 liability of Main Pass at December 31, 2003 reflecting changes in projected timing of certain reclamation activates.

b. Includes $0.5 million of accretion charges following adoption of SFAS 143, a $0.1 million reduction of the reclamation liabilities upon adoption of SFAS 143, $0.7 million of reclamation costs incurred at the Eugene Island Blocks 193/208/215 field to remove structures that were damaged by a hurricane in 2002 and a $0.4 million reduction in the estimated future SFAS 143 liabilities at December 31, 2003, reflecting changes in the projected timing of certain reclamation activities.

c. Reflects the completion of the reclamation activities at the Caminada Sulphur mine during the second quarter of 2002 ($14.5 million) and a reduction of the estimated Phase I Main Pass reclamation costs based on the fixed cost contract with Offshore Fabricators Inc. totaling $5.2 million during the third quarter of 2002 (Note 2). Also reflects $5.6 million of reclamation costs incurred at the Main Pass sulphur facilities during 2002.

d. Includes reductions of $1.2 million associated with McMoRan's sale of certain oil and gas properties during the first half of 2002 (Note 3). Also reflects a newly-formed joint venture assuming the reclamation liability for Main Pass oil operations, which had previously totaled $9.4 million.

e. Reflects $5.4 million of additional reclamation liabilities assumed in the transaction in which McMoRan purchased the remaining 16.7 percent interest in Main Pass Block 299 from Homestake Sulphur Company LLC in June 2001 (Note 2). Also reflects $10.7 million of reclamation costs incurred during 2001, including $9.8 million for Main Pass with the remainder associated with the Caminada and Port Sulphur facilities.

f. Expenses include an accrual of $2.3 million for additional costs to abandon the unsuccessful Vermilion Block No. 3 exploratory well drilled in 2000. During 2001, McMoRan incurred a total of $2.5 million of previously accrued reclamation costs, which was partially offset by $1.7 million of additional reclamation obligations associated with its purchase of Homestake's 16.7 percent interest in the Main Pass oil operations (Note 2).

No other schedules have been included because they are not required, not applicable or the information has been included elsewhere herein.

SIGNATURES

Pursuant to the requirements of Section 13 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 on March 15, 2004.

McMoRan Exploration Co.

By: /s/ Glenn A. Kleinert
Glenn A. Kleinert
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and the capacities indicated, on March 15, 2004.

* James R. Moffett	Co-Chairman of the Board
* Richard C. Adkerson	Co-Chairman of the Board
* B. M. Rankin, Jr.	Vice Chairman of the Board
* C. Howard Murrish	Executive Vice President
/s/ Glenn A. Kleinert Glenn A. Kleinert	President and Chief Executive Officer
/s/ Nancy D. Parmelee Nancy D. Parmelee	Senior Vice President, Chief Financial Officer and Secretary (Principal Financial Officer)
* C. Donald Whitmire, Jr.	Vice President and Controller – Financial Reporting (Principal Accounting Officer)
* Robert A. Day	Director
* Gerald J. Ford	Director
* H. Devon Graham, Jr.	Director
* J. Taylor Wharton	Director

*By: /s/ Richard C. Adkerson
Richard C. Adkerson
Attorney-in-Fact

McMoRan Exploration Co.
Exhibit Index

Exhibit Number

2.1	Agreement and Plan of Mergers dated as of August 1, 1998. (Incorporated by reference to Annex A to McMoRan's Registration Statement on Form S-4 (Registration No. 333-61171) filed with the SEC on October 6, 1998 (the McMoRan S-4)).
3.1	Amended and Restated Certificate of Incorporation of McMoRan. (Incorporated by reference to Exhibit 3.1 to McMoRan's 1998 Annual Report on Form 10-K (the McMoRan 1998 Form 10-K)).
3.2	Certificate of Amendment to the Amended and Restated Certificate of Incorporation of McMoRan. (Incorporated by reference to Exhibit 3.2 of McMoRan's First-Quarter 2003 Form 10-Q).
3.3	Amended and Restated By-laws of McMoRan as amended effective February 2, 2004.
4.1	Form of Certificate of McMoRan Common Stock (Incorporated by reference to Exhibit 4.1 of the McMoRan S-4).
4.2	Rights Agreement dated as of November 13, 1998. (Incorporated by reference to Exhibit 4.2 to McMoRan 1998 Form 10-K).
4.3	Amendment to Rights Agreement dated December 28, 1998. (Incorporated by reference to Exhibit 4.3 to McMoRan 1998 Form 10-K).
4.4	Standstill Agreement dated August 5, 1999 between McMoRan and Alpine Capital, L.P., Robert W. Bruce III, Algenpar, Inc, J.Taylor Crandall, Susan C. Bruce, Keystone, Inc., Robert M. Bass, the Anne T. and Robert M. Bass Foundation, Anne T. Bass and The Robert Bruce Management Company, Inc. Defined Benefit Pension Trust. (Incorporated by reference to Exhibit 4.4 to McMoRan's Third Quarter 1999 Form 10-Q).
4.5	Form of Certificate of McMoRan 5% Convertible Preferred Stock (McMoRan Preferred Stock). (Incorporated by reference to Exhibit 4.5 to McMoRan's Second Quarter 2002 Form 10-Q).
4.6	Certificate of Designations of McMoRan Preferred Stock. (Incorporated by reference to Exhibit 4.6 to McMoRan's Third-Quarter 2002 Form 10-Q).
4.7	Warrant to Purchase Shares of Common Stock of McMoRan Exploration Co. dated December 16, 2002. (Incorporated by reference to Exhibit 4.7 to McMoRan's 2002 Form 10-K).
4.8	Warrant to Purchase Shares of Common Stock of McMoRan Exploration Co. dated September 30, 2003.
4.9	Registration Rights Agreement dated December 16, 2002 between McMoRan Exploration Co. and K1 USA Energy Production Corporation. (Incorporated by reference to Exhibit 4.8 to McMoRan's 2002 Form 10-K).
4.10	Indenture dated as of July 2, 2003 by and between McMoRan and The Bank of New York, as trustee. (Incorporated by reference to Exhibit 4.9 to McMoRan's Second-Quarter 2003 Form 10-Q).
4.11	Registration Rights Agreement dated July 2, 2003 by and between McMoRan, as issuer

and Merrill Lynch, Pierce, Fenner & Smith Incorporated and Jefferies & Company Inc., as initial purchasers. (Incorporated by reference to Exhibit 4.10 to McMoRan's Second-Quarter 2003 Form 10-Q).

4.12 Collateral Pledge and Security Agreement dated as of July 2, 2003 by and among McMoRan, as pledger, The Bank of New York, as trustee, and the Bank of New York, as collateral agent. (Incorporated by reference to Exhibit 4.11 to McMoRan's Second-Quarter 2003 Form 10-Q).

10.1 Main Pass 299 Sulphur and Salt Lease, effective May 1, 1988. (Incorporated by reference to Exhibit 10.1 to McMoRan's 2001 Annual Report on Form 10-K (the McMoRan 2001 Form 10-K)).

10.2 IMC Global/FSC Agreement dated as of March 29, 2002 among IMC Global Inc., IMC Global Phosphate Company, Phosphate Resource Partners Limited Partnership, IMC Global Phosphates MP Inc., MOXY and McMoRan. (Incorporated by reference to Exhibit 10.10 to McMoRan's Second Quarter 2002 Form 10-Q).

10.3 Amended and Restated Services Agreement dated as of January 1, 2002 between McMoRan and FM Services Company. (Incorporated by reference to Exhibit 10.3 to McMoRan's Second-Quarter 2003 Form 10-Q).

10.4 Letter Agreement dated August 22, 2000 between Devon Energy Corporation and Freeport Sulphur. (Incorporated by reference to Exhibit 10.36 to McMoRan's Third-Quarter 2000 Form 10-Q).

10.5 Agreement for Purchase and Sale dated as of August 1, 1997 between FM Properties Operating Co. and MOY (Incorporated by reference to Exhibit 10.27 to McMoRan's 2001 Form 10-K).

10.6 Asset Purchase Agreement dated effective December 1, 1999 between SOI Finance Inc., Shell Offshore Inc. and MOXY. (Incorporated by reference to Exhibit 10.33 in the McMoRan 1999 Form 10-K).

10.7 Employee Benefits Agreement by and between Freeport-McMoRan Inc. and Freeport Sulphur (Incorporated by reference to Exhibit 10.29 to McMoRan's 2001 Form 10-K).

10.8 Purchase and Sales agreement dated January 25, 2002 but effective January 1, 2002 by and between MOXY and Halliburton Energy Services, Inc. (Incorporated by reference to Exhibit 10.1 to McMoRan's Current Report on Form 8-K dated February 22, 2002.)

10.9 Purchase and Sale Agreement dated as of March 29, 2002 by and among Freeport Sulphur, McMoRan, MOXY and Gulf Sulphur Services Ltd., LLP. (Incorporated by reference to Exhibit 10.37 to McMoRan's First-Quarter 2002 Form 10-Q.)

10.10 Turnkey contract for the reclamation removal, site clearance and scrapping of Main Pass Block 299 dated as of March 2, 2002 between Offshore Specialty Fabricators Inc. and Freeport Sulphur. (Incorporated by reference to Exhibit 10.38 to McMoRan's First-Quarter 2002 Form 10-Q.)

10.11 Purchase and Sale Agreement dated May 9, 2002 by and between MOXY and El Paso Production Company. (Incorporated by reference to Exhibit 10.28 to McMoRan's Second Quarter 2002 Form 10-Q).

10.12 Amendment to Purchase and Sale Agreement dated May 22, 2002 by and between MOXY and El Paso Production Company. (Incorporated by reference to Exhibit 10.29 to McMoRan's Second Quarter 2002 Form 10-Q).

10.13	Master Agreement dated October 22, 2002 by and among Freeport-McMoRan Sulphur LLC, K-Mc Venture LLC, K1 USA Energy Production Corporation and McMoRan Exploration Co. (Incorporated by reference to Exhibit 10.18 to McMoRan's 2002 Form 10-K).
10.14	Amended and Restated Limited Liability Company Agreement of K-Mc Venture I LLC, a Delaware Limited Liability Company, dated December 16, 2002. (Incorporated by reference to Exhibit 10.19 to McMoRan's 2002 Form 10-K).
	Executive and Director Compensation Plans and Arrangements (Exhibits 15 through 27).
10.15	McMoRan Adjusted Stock Award Plan, as amended.
10.16	McMoRan 1998 Stock Option Plan, as amended.
10.17	McMoRan 1998 Stock Option Plan for Non-Employee Directors, as amended.
10.18	McMoRan 2000 Stock Incentive Plan, as amended.
10.19	McMoRan 2001 Stock Incentive Plan, as amended.
10.20	McMoRan 2003 Stock Incentive Plan, as amended.
10.21	McMoRan's Performance Incentive Awards Program as amended effective February 1, 1999. (Incorporated by reference to Exhibit 10.18 to McMoRan's 1998 Form 10-K).
10.22	McMoRan Financial Counseling and Tax Return Preparation and Certification Program, effective September 30, 1998. (Incorporated by reference to Exhibit 10.26 to McMoRan's First-Quarter 2003 Form 10-Q)
10.23	Agreement for Consulting Services between Freeport-McMoRan and B. M. Rankin, Jr. effective as of January 1, 1991)(assigned to FM Services as of January 1, 1996); as amended on December 15, 1997 and on December 7, 1998. (Incorporated by reference to Exhibit 10.32 to McMoRan 1998 Form 10-K).
10.24	Supplemental Agreement between FM Services and B.M. Rankin, Jr. dated February 5, 2001. (Incorporated by reference to Exhibit 10.36b to McMoRan's 2000 Form 10-K).
10.25	Supplemental Agreement between FM Services and B.M. Rankin, Jr. dated December 13, 2001 (Incorporated by reference to Exhibit 10.49 to McMoRan's 2001 Form 10-K).
10.26	Supplemental Agreement between FM Services and Morrison C. Bethea dated October 15, 2001, providing an Amendment to the Consulting Agreement of November 1, 1993 as amended and Supplemental Agreement of December 21, 1999 (Incorporated by reference to Exhibit 10.49 to McMoRan's 2001 Form 10-K).
10.27	Supplemental Agreement between FM Services and Morrison C. Bethea dated October 21, 2003, providing an Amendment to the Consulting Agreement of November 1, 1993 as amended.
12.1	Computation of Ratio of Earnings to Fixed Charges
14.1	Ethics and Business Conduct Policy.

21.1	List of subsidiaries
23.1	Consent of Ernst & Young LLP
23.2	Consent of Ryder Scott Company, L.P.
24.1	Certified Resolution of the Board of Directors of McMoRan authorizing this report to be signed on behalf of any officer or director pursuant to a Power of Attorney.
24.2	Powers of Attorney pursuant to which this report has been signed on behalf of certain officer and directors of McMoRan.
31.1	Certification of Principal Executive Officer pursuant to Rule 13a–14(a)/15d-14(a).
31.2	Certification of Principal Financial Officer pursuant to Rule 13a–14(a)/15d-14(a).
32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. Section 1350.
32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. Section 1350.

BOARD OF DIRECTORS

James R. Moffett, 1994 †
Co-Chairman of the Board
McMoRan Exploration Co.

Richard C. Adkerson, 1994
Co-Chairman of the Board
McMoRan Exploration Co.

Robert A. Day (1), 1994
Chairman of the Board and
Chief Executive Officer
The TCW Group, Inc.

Gerald J. Ford (1,3), 1998
Chairman of the Board
Liberté Investors Inc.

H. Devon Graham, Jr. (1,2,3), 1999
President
R.E. Smith Interests, Inc.

B. M. Rankin, Jr., 1994
Vice Chairman of the Board
McMoRan Exploration Co.
Private Investor

Dr. J. Taylor Wharton (2), 2000
Special Assistant to the President for
Patient Affairs
Professor, Gynecologic Oncology
The University of Texas
M.D. Anderson Cancer Center

Advisory Directors

Morrison C. Bethea
Chief of Thoracic Surgery,
Tenet Memorial Medical Center
Cardiac, Thoracic and Vascular Surgeon
Clinical Professor of Surgery,
Tulane University Medical Center

Gabrielle K. McDonald
Judge, Iran-United States Claims Tribunal
Special Counsel on Human Rights to the
Chairman of the Board
Freeport-McMoRan Copper & Gold Inc.

Board Committees:
(1) Audit
(2) Corporate Personnel
(3) Nominating and Corporate Governance
† Year Joined Board of
Company or its Predecessors

MANAGEMENT

James R. Moffett
Co-Chairman of the Board

Richard C. Adkerson
Co-Chairman of the Board

Glenn A. Kleinert
President & Chief Executive Officer

Operations:

C. Howard Murrish
Executive Vice President
Exploration

David C. Landry
Vice President
Development

Administration & Finance:

W. Russell King
Senior Vice President
Federal Government Affairs

Nancy D. Parmelee
Senior Vice President
Chief Financial Officer & Secretary

Kathleen L. Quirk
Senior Vice President & Treasurer
Finance and Business Development

John G. Amato
General Counsel

William L. Collier, III
Vice President
Communications

Dean T. Falgoust
Vice President
Tax

D. James Miller
Vice President
Environmental Affairs

C. Donald Whitmire, Jr.
Vice President &
Controller-Financial Reporting

Internal Auditors:

Deloitte & Touche LLP

SHAREHOLDER INFORMATION

The Investor Relations Department will be pleased to receive any inquiries about the company's securities or any phase of the company's activities.

Investor Relations Department
1615 Poydras Street
New Orleans, LA 70112
(504)582-4000
www.mcmoran.com

Questions about lost certificates or notifications of change of address should however be directed to MMR's transfer agent and registrar, Mellon Investor Services LLC.

Mellon Investor Services LLC
Overpeck Centre, 85 Challenger Road
Ridgefield Park, NJ 07660
(888)208-1794
www.melloninvestor.com

McMoRan Exploration Co.

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New Orleans, LA 70112
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